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15 August 1980

USSR Report

ENERGY

(FOUO 15/80)

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15 August 1980

USSR REPORT

ENERGY

(FOUO 15/80)

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980

CONTENTS

FUELS

FUELS

UDC 622.276.43

UNIQUE FEATURES OF WATER FLOODING OF WELLS IN SAMOTLOR DEPOSIT

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 pp 3-5

[Article by F. N. Marichev, V. G. Safin, and A. A. Glazkov]

[Text] Horizon AB_{4-5} is a layer of fine- and medium-grained sandstone and aleurolite interlayered by clays and clayey aleurolite. The porosity of constituent rock varies from 19.1 to 33.5 percent. Permeability attains 3,[illegible]00 mD and more. According to laboratory core analysis the mean permeability in the horizontal and vertical directions is 1,072 and 670 mD respectively. The latter indicates that the stratum has low anisotropy, which promotes formation of conical encroachment sites at the oil wells.

Geological materials obtained in the course of operation of wells in the northeast part of horizon AB_{4-5} were analyzed to determine the unique features of the flooding of wells drilled in the bed's water-oil zone.

A plot consisting entirely of a water-oil deposit in the horizon was marked out by an arbitrary boundary. This plot contained wells in the north part of exploitation block IV and in blocks V and VI, with a minor exception.

Bed pressure was not maintained in the isolated plot by pumping water into injection wells. Consequently flooding of the wells was the result of causes not associated with penetration of pumped water through the bed.

Out of 159 wells that were operating in the isolated plot on 1 January 1977, 62 wells produced water-containing petroleum.

The table below shows the distribution of wells in terms of water concentration.

Interval of Change in Well Product Water Concentration, %	Number of Wells	
	On 1 Jan 77	On 1 Jan 78
0-10	29	14
10-20	13	17
20-30	10	11
30-40	5	10
40-50	3	10
50-60	1	5
60-70	1	7
>70	--	3

As we can see from the table, on 1 January 1977 84 percent of the wells delivered a product with a water concentration up to 30 percent, and only 3.2 percent of the wells delivered a product with a water concentration over 50 percent. In 1977, 17 of the wells were flooded, and two were inactive. Thus on 1 January 1978, out of 77 flooded wells, 54.5 percent had a product water concentration of up to 30 percent, and 17 wells (19.5 percent) had a water concentration over 50 percent.

The thicknesses of the beds between the initial level of the oil-water interface and the lower perforations of all flooded wells in the water-oil part of the horizon are compared below.

0—2	—	12—14	11
2—4	1	14—16	7
4—6	1	16—18	5
6—8	7	18—20	7
8—10	12	>20	3
10—12	22		

A total of only 11.4 percent of the wells in the isolated plot have an interface from 2 to 8 meters thick, that of 63.8 percent of the wells is from 8 to 16 meters, and that of 24.8 percent of the wells is over 16 meters.

The distribution of the thicknesses of the interface bed is similar for the flooded wells. Consequently the size of the interface bed between the initial position of the oil-water interface and the lower well perforations has no important association with the causes of the flooding of wells in the water-oil part of horizon AB_{4-5}.

Generalization and analysis of geological material obtained from oil wells permitted us to reveal, from the entire diversity of the flooding curves describing several groups of wells with the most typical features, those distinguished by the growth rate of water concentration:

Group I: slow, uniform growth of water concentration in well product, up to a comparatively low value (less than 40 percent as a rule) over a lengthy period of time (39 wells).

Group II: high rate of well product encroachment by water for a short period of time (within a single year) (10 wells).

Group III: abrupt flooding of well product in a short period of time, followed by stabilization of water concentration (7 wells).

Group IV: slow, uniform growth in water concentration, or presence of a low water concentration maintained constant over a long period of time, followed by swift encroachment of the product by water to a level of 50-70 percent (3 wells).

Group V: fluctuations in water concentration of well product, sometimes repeating themselves over a long period of time. These fluctuations attain 40-50 percent (8 wells).

This division of wells on the basis of types of flooding is somewhat arbitrary.

The largest group of wells (39) experienced the first type of flooding, the water concentration growth rate being 0.2-3 percent per month.

In the second and third types of flooding the growth rate of product water concentration varies within broad limits, from 5 to 25 percent per month as a rule. The averages are 5.9 percent per month for Group II and 15 percent per month for Group III.

The flooding dynamics of wells drilled into the water-oil part of the horizon obviously depend on many factors of both geological and technological nature. An analysis of the dependence between type of well flooding and the thickness of the interface bed, performed in relation to the different groups of wells, reveals no dependencies at all. As we can see from Figure 1, the limits of the flooding rate for the first group of wells vary from 0.2 to 3 percent per month when the interface bed is from 7 to 23 meters thick.

The bed pressure in the isolated plot was 160-173 kg/cm^2. Bottom hole pressure was maintained at 128-164 kg/cm^2; in this case the depression created in the bed varies for individual wells within rather broad limits--from 8-12 to 44 kg/cm^2. Unit depression (depression per meter of thickness of the interface bed) varies from 1.3 to 6.4 kg/cm$^2\cdot$m.

The following dependencies were plotted: the time of waterless petroleum extraction and well flooding rate on depression and on unit depression, in relation to the different well groups, and separately in relation to wells with a monolithic interface bed and with fractionated, dense laminae. These dependencies showed that a close mutual correlation is not observed among the parameters studied.

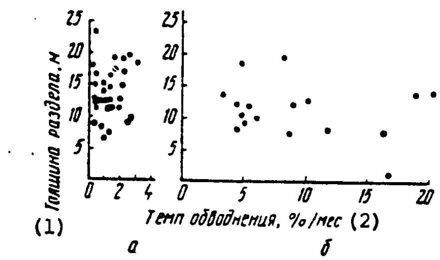

Figure 1. Dependence of Well Flooding Rate on Bed Thickness for Well Groups Experiencing Type I(*a*) and II, III, and V Flooding (*b*)

Key:

1. Interface thickness, meters
2. Flooding rate, percent per month

Analysis of the flooded wells in the isolated plot does not permit unambiguous establishment of a particular influence upon the flooding rate by such factors as relative dissection of the oil-bearing layer of the bed by the perforation process, the rate of fluid extraction, and presence of clayey interlayers, and their thickness. But almost all wells with a high flooding rate classified as types II, III, and V are located near the outer contour of the oil-bearing bed.

On the other hand wells distinguished by type I flooding and low growth of product water concentration are located in the center of the selected plot.

Curves describing change in the proportion of petroleum, f_p, depending on total fluid extracted were plotted for flooded wells (figures 2*a*,*b*, and 3). As we can see from Figure 2, wells experiencing type I flooding exhibit a larger petroleum extraction volume during the waterless period in comparison with wells experiencing type II, III, and V flooding.

Wells in groups II, III, and V exhibit a higher rate of decline of the proportion of petroleum in the product, and lower f_p values for the same volume of fluid extracted from the wells, in comparison with wells in Group I.

The high rate of water encroachment of the well product cannot be explained by a vertical rise in the water-oil interface, since only 10,000-20,000 tons of petroleum were extracted from wells in groups II, III, and IV during the waterless period. This clearly does not correspond to the amount of petroleum extracted from between the initial position of the oil-water interface and the perforation interval, assuming a vertical rise in the oil-water interface. Second, at the existing distances between the oil-water interface and the lower perforations (7-19 meters), the time of waterless extraction does not correspond to the time of waterless well exploitation that would be consistent with a vertical rise in the oil-water interface.

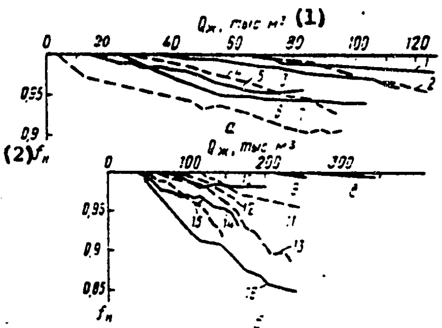

Figure 2. Change in Proportion of Petroleum in Total Volume of Liquid Extracted From Wells 3472 (*1*), 3382 (*2*), 3535 (*3*), 3475 (*4*), 2927 (*5*), 3470 (*6*), 3559 (*7*), 3046 (*8*), 3465 (*9*), 3372 (*10*), 3473 (*11*), 3381 (*12*), 3747 (*13*), 3474 (*14*), 3358 (*15*), and 3044 (*16*) Experiencing Type I Flooding

Key:
1. Q_f, thousands of m^3
2. f_p

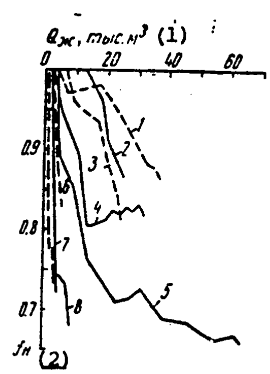

Figure 3. Change in Proportion of Petroleum in Total Fluid Extracted From Wells 4006 (*1*), 4262 (*2*), 4061 (*3*), 3645 (*4*), 3365 (*5*), 3997 (*6*), 3754 (*7*), and 4210 (*8*), Experiencing Type II, III, and V Flooding

Key:
1. Q_f, thousands of m^3 2.
2. f_p

Flooding of wells located near the contour of the oil-bearing bed can be explained by mixed penetration of water into wells; a cone of water is drawn up concurrently with active invasion of surrounding water through individual highly permeable interlayers.

Invasion of water through non-watertight cement casings in wells of horizon AB_{4-5} also obviously occurs. Wells with a non-watertight cement casing have a short waterless period of exploitation, equal to 1-3 months, or they immediately begin producing water-containing products despite the fact that their interface beds have a thickness of significant magnitude.

As an example there are grounds for suggesting that the cement casings of wells 3559, 3643, 3645, 3928, 3932, 3997, 4179, 4210, 4262, and 4147 are non-watertight.

The thickness of the interface bed of wells 3932, 3997, 4179, and 4262 is within 7-9.5 meters, while that of wells 3559, 3643, 3645, 3928, 4210, and 4147 is 11-19 meters. Despite this, flooding set in after 2-3 months of exploitation, while well 4147 began producing water from the moment it was placed into operation. A unique feature can be noted in the dynamics of well flooding: From the moment that water arises, its concentration remains constant for a long period of exploitation, within 10-25 percent as a rule.

As an example the product water concentration of well 4147 remained within 10-14 percent throughout the entire 18 months of operation, while that of well 3997 stayed at 25 percent (18 months).

Flooding dynamics of this nature may be explained by invasion of water through cracks and channels in the cement collar situated beyond the casing.

This analysis of geological operating data and the flooding dynamics of wells in the water-oil part of horizon AB_{4-5} shows that flooding of wells resulting from invasion of water through a non-watertight cement collar is not the principal cause for horizon AB_{4-5}. Operation of only a few wells with a non-watertight cement collar significantly influences the total quantity of incidentally extracted water.

Thus if well repair and isolation operations are to be successful in the development of the water-oil part of horizon AB_{4-5}, effective ways to control conical flooding of wells located in the central part of the horizon must be employed. A method of selective isolation of flooded intercalations must be sought for wells experiencing mixed flooding through cones and by the channeling of surrounding water through individual interlayers.

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FUELS

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EXPERIENCE IN REGULATING WELL EXPLOITATION BY CHANGING FILTRATION FLOWS

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 -- 6-7

[Article by A. U. Aytkulov, D. A. Goryunov, and Yu. P. Kislyakov]

[Text] The Uzen' deposit is represented by a platform anticlinal fold of almost latitudinal orientation.

The productive section of the oilfield is composed of Jurassic terrigenic deposits. The revealed horizons are multilayered and heterogeneous. Not counting the small intercalations, the most uniform beds number from five to fourteen. A typical feature of the beds is zonal change in thickness and permeability. Zones with higher (above-average) parameter values can be distinguished. Zonality is expressed to the greatest extent in horizon XIII.

Exploitation of the deposit involves contour flooding by means of rows of injection wells transverse to the fold's orientation.

The flooding process usually goes on continuously, not counting interruptions for repairs, preventive maintenance, and analysis.

Contour flooding at the Uzen' deposit has elicited intense water encroachment about the wells.

To reveal the influence of flooding upon the resulting water concentration of the petroleum extracted, on 24 February 1976 injection wells 63, 114, 1409, 1446, 1448, 1452, 1501, 1779, 1781, 1783, and 1782 in the southern part of injection row VIa were shut down, and the pumping volume was increased by more than 22 times in the northern part of injection row VIa. The change in the pumping procedure was made in the most highly flooded blocks of the deposit--6a and 7.

Subsequent research and analysis of the operational indicators of injection and production wells showed that injection influences not all wells of injection row VIa, but basically only the production wells of the first exploitation rows. In all, there were 41 production wells within the zone of injection's active influence.

In geological respects the zone of injection influence is mainly located within the bed merging zone of horizon XIII, and insignificantly in the layer merging zone of horizon 14 and in the bed separation zone of horizon XIII (at the north side of the blocks).

Horizons 13 and 14 are multilayered. When the horizons are viewed in cross section, both individual, relatively thick beds and intercalations from 0.2 to 0.4 meters thick can be distinguished. The number of beds and intercalations numbers from 10 to 20 and more. The beds and intercalations are separated by dense, impermeable carbonate argillites not inferior to sandstone in thickness. For this reason the apparent thickness of sandy beds seen on a standard logging diagram, is significantly greater than the effective thickness, sometimes by more than a factor of two. For example the apparent thickness of monolithic sandstone at well 1783 is 41 meters, while the effective thickness is not more than 18 meters.

The effective thickness of horizons XIII + XIV in the merging zones is 26-40 meters, while in the separation zones it does not exceed 10 meters. Permeability in the merging zones attains 500-1,000 mD and more, while in separation zones it does not exceed 150 mD.

The zone of injection influence is complicated by a tectonic disturbance--a low amplitude, enclosed fault that passes almost to injection row VIa.

Cessation of water injection for 291 days caused a drop in bed pressure in the southern part of blocks 6a and 7, down to the gas saturation pressure, while bottom hole pressure dropped to 5-10 percent below saturation pressure.

Twenty-five wells in the southern part reacted actively to injection; data from these wells were used to plot curves describing changes in mean daily petroleum and fluid delivery of one well, the water concentration in the extracted fluid, and reservoir and bottom hole pressure. A drop in reservoir pressure caused an increase in the mean daily delivery of fluid and petroleum by 42 and 26 percent respectively. The difference in the decrease in delivery of fluid and petroleum can be explained by a 17 percent reduction in the concentration of water in the extracted fluid. A significant decrease in bottom hole pressure caused petroleum-saturated layers that had not produced previously and which locally possessed a low reservoir pressure to begin producing. Reduction of reservoir pressure caused a decrease in the flow from flooded layers, and even its cessation. This is confirmed not only analytically but also by data acquired by geophysical analysis methods applied to production wells 1417, 1441, 1468, 1809, 2293, and 2383.

Estimates made from a prediction of the mean daily delivery of fluid and petroleum by one well and of the water concentration show that because water injection was stopped, fluid delivery was 311,100 m^3 low.

If we assume that while the injection wells in the southern part of transverse row VIa were shut down (for 291 days) all incidental water was extracted from the flooded beds that had produced earlier (prior to cessation of injection) and which continued to produce, the concentration of water in these beds would vary in accordance with the predicted dynamics, which is entirely possible. We can also determine the amount of petroleum extracted from beds which had never produced before. By dividing the actual amount of water extracted incidentally in the 291 days by the predicted proportionate concentration of water, we would get the estimated delivery of fluid from previously producing (prior to cessation of injection) beds that continue to produce. The difference between the total amount of fluid actually extracted in the 291 days and the estimated delivery would equal the amount of petroleum extracted from beds which had never produced before but which began producing now. The computations show that in the case under examination here, the petroleum yield would be 28,900 m^3.

At the same time that injection was halted in the southern part of transverse row VIa, water injection was increased by a factor of 2.5 in five injection wells in its northern part. The increase in injection was accompanied by a rise in reservoir pressure and in the injection pressure of the wells from 90-100 to 130-160 kg/cm^2. Observations were maintained on 16 actively reacting wells located mainly in the first production row. Data from these wells were used to plot curves describing changes in the mean daily discharge of petroleum and fluid by a single well, and the concentration of water in the extracted fluid.

An increase in the volume of water injected and of the injection pressure caused a 20 percent increase in fluid yield and a 28 percent increase in petroleum yield. The difference in the increase experienced by the yields of fluid and petroleum can be explained by a 5 percent drop in the water concentration (at the end of the period). The decrease in water concentration can be explained by the fact that a significant rise in injection pressure caused beds and petroleum-saturated intercalations that had never produced before to begin producing. This conclusion is also confirmed by investigation of injection wells 1453, 1454, 1457, and 1784 with deep-well flowmeters. A factor describing the extent to which the beds were affected by injection in these wells rose by 64 percent in response to a 67 percent increase in injection pressure. The values of these factors, given in relation to bed thickness, and the injection pressures are presented below.

Injection Pressure, kg/cm^2	Factor, Fractions of Units
80-100	0.31
100-120	0.43
120-140	0.50
140-160	0.51

Computations based on prediction of the mean daily yield of fluid from a single well and of the concentration of water in it show that during the period of increasing injection (291 days), as a result of growth in the volume of water injected and in the injection pressure the additional discharge of fluid was 49,100 m^3, to include 40,200 m^3 of petroleum.

If we assume that during the entire injection period all incidental water was extracted from flooded beds that had produced formerly (before injection was increased) and that its concentration in these beds changed in accordance with the predicted dynamics, then, as in the previous case, we can similarly compute the amount of petroleum extracted from beds that previously had not been producing, after water injection is halted. The computations show that it was 26,200 m^3.

As we can see from these data, the effectiveness, in terms of petroleum, of causing beds to produce by increasing injection pressure within them is greater than it is in response to cessation of injection.

Thus to improve development of the reserves, it would be suitable to periodically halt or significantly limit injection in highly flooded blocks of the field, and increase it in the least-flooded block. This should raise the effectiveness of contour flooding.

The same can be done with injection rows VIa and VIII. Injection would need to be halted in the former, and it should be intensified in the latter--that is, injection should be increased by not less than a factor of two.
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EFFECTIVE USE OF CYCLIC METHOD FOR FLOODING LOW POROSITY CARBONATE RESERVOIRS

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 pp 8-10

[Article by Ya. M. Zaydel', B. I. Levi, and V. P. Rodionov]

[Text] Kashira-Podol'sk depots in the Arlanskoye oilfield are represented by beds Pd_3 and Ksh_1, which are separated from one another by a layer of clayey limestone that extends throughout the entire oil formation. Each of the beds contains two intercalations that are separated into two or three laminae. Dense, slightly fractured limestone with a permeability of 1 mD and a porosity of 3 percent serves as bridges between the intercalations. Exploitation of the Kashira-Podol'sk deposits by displacing the petroleum with water demonstrated the effectiveness of a cyclic flooding method.

As water was pumped in, pressure at the heads of the injection wells changes from 90 to 150 kg/cm^2. An analysis of experimental water injection in the Kashira-Podol'sk deposit established that the optimum injection pressure at the bottom hole of the injection wells is 190 kg/cm^2. A rise in well flooding due to opening of cracks in the bed is observed concurrently with growth in fluid yields in response to a further rise in injection pressure. A temporary reduction of injection pressure going as far as cessation of injection causes a decline in water concentration and yield of fluid, with petroleum discharge remaining almost constant. A variable water injection cycle has a favorable effect upon development of carbonate reservoirs.

The Kashira-Podol'sk deposits satisfy most requirements imposed on successful application of cyclic flooding. They are typified by presence of natural block disintegration, which reveals itself to the greatest degree in response to creation of high pressure gradients; this permits the assumption that a hydrodynamic relationship exists between different laminae of the bed. Creation of high injection pressure for a short time creates a sufficient reserve of reservoir pressure.

Several exploitation variants differing from one another by various parameters characterizing cyclic action were examined in order to reveal the effectiveness of the cyclic flooding method and to establish the optimum conditions for using this method.

The computations were based on a complete hydrodynamic model of the bed making it possible to account for biphasal flow and for the entire complex of hydrodynamic, capillary, gravitational, and elastic forces governing filtration flow. When the appropriate raw data are available, this model can account for hysteresis of relative phasal permeabilities and functions of capillary pressure. The finite-difference method was used to solve the system of equations for biphasal filtration, with a consideration for the compressibility of the fluid and rock.

The element of symmetry of a single-row system of wells was chosen as the element of computation. The distance bewteen rows of wells and between wells in a row was assumed to be 400 meters. The viscosity of the bed's petroleum was 10 cP, and that of injected water was 1 cP. Bottom hole pressure in injection and production wells was adopted equal to 190 and 30 kg/cm^2 respectively.

The heterogeneity of the beds was modeled by introducing, as given, three permeable laminae in each intercalation, and bridges separating the intercalations. In this case the set of laminar permeabilities corresponded to M. M. Sattarov's distribution at $\alpha/k_0 = 0.5$. Next the indicators for exploitation of the two beds were summed.

Changes in permeability of the laminae depending on injection pressure were considered with the formula

$$\kappa = \kappa_0 \cdot \exp \alpha (P - P_0), \qquad (1)$$

where k_0--permeability at initial bed pressure P_0; α--permeability change factor; P--fluid filtration pressure.

The anisotropy factor, which characterizes the relationship between vertical permeability and strike permeability, was adopted equal to 0.1.

Each complete cycle of action upon the oil formation consists of two periods. In the first, the given bottom hole pressures are maintained at the bottom holes of the injection and production wells. In the second period, water injection ceases, while fluid continues to be extracted from the production wells at the given bottom hole pressure.

Variants employing cyclic action were compared with the case of continuous water injection. In this case it was assumed, as a condition, that maximum injection pressure with cyclic flooding matches the corresponding pressure accompanying continuous water injection, and that it is 190 kg/cm^2. This is associated with the existing upper limit upon injection pressure, and it does not elicit additional difficulty when this method is applied in the field.

We first studied the cyclic flooding variants characterized by equal half-cycles of falling and rising bed pressure. In this case the cycle duration varied from 30 to 60 days. Computations showed that change in the period of symmetrical cycles within the indicated range has practically no effect on the increment of petroleum yield (this is true in relation to a 95 percent water concentration), which is about 4 percent. Therefore we devoted our principal attention to studying the influence of nonsymmetrical cycles upon the effectiveness of pulsed action. We studied several variants of cyclic flooding, in which the ratio between the fall time and the rise time of bed pressure varied from 0.5 to 4. The complete period of the cycle in these variants is 60 days.

The rate of petroleum extraction was found to be lower in these variants than with continuous water injection, and the development time was greater. As λ decreases, the extraction rates increase. This can obviously be explained by the fact that the average filtration rate in the bed decreases due to temporary cessation of injection. Because of this, the resulting effect may be associated with two factors. The first is concerned with change in the relationship between gravitational and hydrodynamic forces due to a decrease in filtration rate relative to the basal variant, and the second is associated with intensification of fluid flow between laminae due to the action of elastic forces in the cyclic action situation. However, computations based on the same average filtration rate used in the variant with $\lambda = 2$ but with a constant pressure gradient showed that the first factor is insignificant in these conditions. The change in petroleum yield resulting from the rate decline was about 0.6 percent, which is about seven times less than the effect observed with cyclic water injection (Figure 1, $\lambda = 2$, $\Delta\eta = 4$ percent).

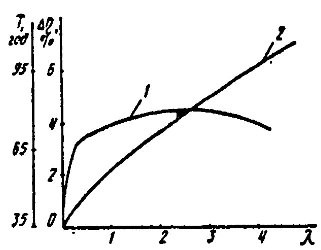

Figure 1. Influence of the Ratio Between the Injection Pressure Rise Time and the Time of Decreasing λ on the Increment in Petroleum Yield, $\Delta\eta$ (as of the Moment of 95 Percent Water Saturation and Development Time)

The nature of the dependence of the petroleum yield increment $\Delta\eta$ on the ratio between the fall time and rise time of bed pressure λ is not monotonic, and it indicates that both half-cycles of the cycles have an influence upon the effectiveness of cyclic action (see Figure 1, curves *1*,*2*). When λ is close to zero--that is, when the half-cycle of falling pressure, t_f, is much smaller than the half-cycle of rising pressure, t_r, in this case the indicators of the process are found to be close to the corresponding indicators obtained in the continuous flooding situation. We also observe a decrease in the effectiveness of cyclic action at high λ values. This can be explained by the fact that when the rise time of bed pressure is much shorter than the fall time, during the rising half-cycle the bed pressure does not have a chance to recover completely, which exhausts the bed's elastic energy reserve and reduces the intensity of fluid flow between laminae in subsequent cycles as well.

As we can see from Figure 1, the dependence of development time upon λ is close to linear, while the petroleum yield is nonlinear in nature. In this case maximum change in the petroleum yield factor is observed at less than $\lambda = 0.5$. As λ increases further, from 1 to 3, the petroleum yield increases by only 0.5 percent, while the development time becomes 30 years longer. Thus the optimum value of λ lies in the interval from 0 to 0.5.

Because the rate of petroleum extraction declines in the initial period of cyclic flooding in comparison with the rate seen with continuous injection, variants in which this method is applied not at the beginning of the development time were examined. It was found in this case that the longer the method's application is postponed, the lower is the increment in petroleum yield. In this case the nature of the dependence existing between $\Delta\eta$ and λ persists.

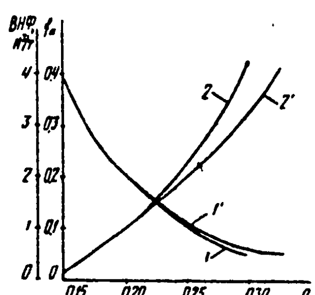

Figure 2. Dependence of the Proportion of Petroleum, f_n, in Well Discharge and the Cumulative Water-Oil Factor on Petroleum Yield: *1*,*2*--continuous water injection; *1'*,*2'*,--cyclic water injection with 80 percent water concentration

Computations showed that for the conditions examined here, it would be most suitable to use the cyclic flooding method, attaining an 80 percent water concentration in the petroleum bed, and 0.5 for the ratio between the fall time of bed pressure and the rise time. In this variant the petroleum yield was 0.327 in relation to 95 percent water concentration, and the development time is 42 years. In the case of continous injection, the petroleum yield is 0.3 in relation to 95 percent water concentration, and the development time is 35 years. We can see from Figure 2 that when cyclic flooding is involved, not only does the petroleum yield increase, but also the water-oil factor decreases, while the proportion of petroleum in the well discharge rises.

Introduction of the cyclic method is usually made difficult due to the need for halting production for a long period of time at existing facilities; hence the low use factor for the power output capacities. Moreover when water injection is halted in winter, the water lines and injection well manifolds freeze.

Combining the method of separate injection of water into two productive beds (in the upper bed through the intertubular space, and in the lower bed through the pump and compressor pipes based on cyclic flooding is suggested as a way to exclude these phenomena. At $\lambda \leqslant 1$, separate injection of water into the beds makes it possible to achieve a continuous flow of water in the inlets, while selection of the appropriate flow regulators at the heads of the injection wells would permit establishment of the appropriate water delivery rate.

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FUELS

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POSSIBILITY FOR RAISING OIL, GAS YIELD FROM FLOODED BEDS

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 pp 10-13

[Article by G. V. Klyarovskiy, R. V. Mysevich, and B. G. Parakhin]

[Text] Many oil formations have a complex geological structure, a variable lithologic and facial composition, and rock with poor reservoir properties. In a number of cases, because of the absence of active perimeter water and the equality of the initial saturation pressure and the bed pressure, use of dissolved gas is a natural way to work such formations.

The initially high yields of petroleum (up to 250 tons per day) from low porosity rock strata have been the product of exploitation of the wells at high bed pressure and low viscosity of petroleum in the bed, which does not exceed 1 cP at a gas saturation ratio greater than 200 m^3/m^3.

Hydrodynamic computations and results of the first years of development of the examined formations showed that under natural conditions, the oil extraction factor would attain 0.12 in the best case. In such formations, therefore, following their initial development with the use of dissolved gas, various systems have been introduced to maintain bed pressure by means of water injection.

However, an analysis of the state of such developments would show that when petroleum delivery decreases to an amount that would make the injection system of operation unprofitable, the petroleum output would be relatively low even if additional flooding sites are introduced, the network of injection wells is made more dense, and if various technical geological measures are implemented. Therefore it becomes important to seek ways to increase the petroleum output. One such way might be to continue to exploit almost completely flooded formations with dissolved gas after cessation of water injection, since they would maintain a high bed pressure.

In each case, the effectiveness of converting from a pressure system to a depletion system would depend on the geological-operational factors, the bedding properties of the fluids saturating the reservoir, the residual oil and gas saturation of the beds, and the development conditions. In order to compute indicators for development of formations with dissolved gas, we will derive, for the conditions examined here, the dependence between bed pressure decline and fluid discharge (and change in the bed's oil and water saturation). In this case the balance equations for the yields of oil q_H, gas q_Γ, and water q_B would take the form

$$q_{\text{н}}=-\Omega\cdot\frac{d}{dt}\left[\frac{\rho_{\text{н}}}{\beta(P)}\right]; \qquad (1)$$

$$q_{\text{г}}=-\Omega\cdot\frac{d}{dt}\left[(1-\rho_{\text{н}}-\rho_{\text{в}})\cdot P\right]-$$

$$-\Omega\cdot\frac{d}{dt}\left[\frac{\rho_{\text{н}}}{\beta(P)}\cdot S(P)\right]; \qquad (2)$$

$$q_{\text{в}}=-\Omega\frac{d\rho_{\text{в}}}{dt}. \qquad (3)$$

where Ω--formation's pore space volume; ρ_H, ρ_B--oil and water saturation of the bed respectively; $\beta(P)$ and $S(P)$--volumetric coefficient and gas concentration of bed oil depending on pressure (P); t--formation exploitation time.

Separating the left and right parts of equations (2) and (3) correspondingly into the left and right parts of equation (1) and equating the factors on the right to the value of the gas and water factors (4), (5), following simple transformations we get differential equations (6) and (7):

$$\Gamma_{\text{г}}=P\frac{F_{\text{г}}}{F_{\text{н}}}\cdot\frac{\mu_{\text{н}}(P)}{\mu_{\text{г}}(P)}\cdot\beta(P)+S(P); \qquad (4)$$

$$\Gamma_{\text{в}}=\frac{F_{\text{в}}}{F_{\text{н}}}\cdot\beta(P)\cdot\frac{\mu_{\text{н}}(P)}{\mu_{\text{в}}(P)}. \qquad (5)$$

where F_Γ, F_H, F_B--phasal permeability for gas, oil, and water respectively in a triphasal system; $\mu_H(P)$, $\mu_\Gamma(P)$, $\mu_B(P)$--viscosity of bed oil, gas, and water depending on pressure.

$$\frac{d\rho_{\text{н}}}{dP}=\frac{\frac{\rho_{\text{н}}}{\beta(P)}\cdot\left\{P\cdot\beta'(P)\left[\frac{F_{\text{г}}}{F_{\text{н}}}\cdot\frac{\mu_{\text{н}}(P)}{\mu_{\text{г}}(P)}+\frac{F_{\text{в}}}{F_{\text{н}}}\cdot\frac{\mu_{\text{н}}(P)}{\mu_{\text{в}}(P)}\right]+S'(P)\right\}+1-\rho_{\text{н}}-\rho_{\text{в}}}{P\cdot\left[\frac{F_{\text{г}}}{F_{\text{н}}}\cdot\frac{\mu_{\text{н}}(P)}{\mu_{\text{г}}(P)}+\frac{F_{\text{в}}}{F_{\text{н}}}\cdot\frac{\mu_{\text{н}}(P)}{\mu_{\text{в}}(P)}+1\right]}; \qquad (6)$$

$$\frac{d\rho_{\text{в}}}{dP}=\frac{F_{\text{в}}}{F_{\text{н}}}\cdot\frac{\mu_{\text{н}}(P)}{\mu_{\text{в}}(P)}\cdot\left[\frac{d\rho_{\text{н}}}{dP}-\frac{\rho_{\text{н}}\cdot\beta(P)}{\beta(P)}\right]. \qquad (7)$$

As a result of joint solution of differential equations (6) and (7) we can determine change in the oil and water saturation of the beds depending on bed pressure decline. This system of equations is solved by one of the methods of numerical integration.

Let us make the hydrodynamic computations for a uniform formation possessing the properties typical of bed fluids. Let us assume that in the initial period the formation was worked with dissolved gas. Owing to this, bed pressure dropped to 0.65 of the initial pressure. Subsequent development involved flooding at a constant bed pressure equal to 210 kg/cm^2.

When the gasified fluid is displaced by water, part of the free gas remains immobile and causes residual gas saturation. In the formation under examination here, after water injection was started, movement of the gas phase ceased very quickly. In this case residual gas saturation was close to the initial saturation level resulting from development of the formation with dissolved gas. The mean residual gas saturation for the formation was 0.109.

To determine the dependence of development indicators upon residual petroleum reserves, we subjected the first and second variants to hydrodynamic computations, using initial oil-water and gas saturation levels equal respectively to 0.215, 0.616, 0.109, and 0.385, 0.506, 0.109.

The influence of residual gas saturation upon the effectiveness with which the formation was developed was evaluated on the basis of the computations for the third and fourth variants, for which it was hypothesized that as gasified petroleum was displaced by water, all free gas that had formed in the initial period of development was displaced from the bed. The initial oil and water saturation levels are equal to 0.324 and 0.676 for the third variant and 0.494 and 0.506 for the fourth variant respectively.

In order to assess the influence of preliminary depletion of the formation upon the total petroleum output, we perform computations for a fifth variant, in which displacement begins at an initial bed pressure of 315 kg/cm^2, without initial working of the formation with dissolved gas. The formation is subsequently depleted with a free gas phase absent from the bed. For this variant the initial oil and water gas saturation levels are 0.494 and 0.506 respectively. The raw data used in the computations are presented below.

Volume, millions m^3	
Pore space, Ω	118
Bound water, ρ_{CB}	0.19
Bed water viscosity, μ_B, cP	1

Figure 1 shows the physical characteristics of the bed's petroleum. The phasal permeabilities for gas F_Γ, oil F_H, and water F_B were determined using the formulas for a triphasal system.

The numerical method was used to integrate differential equation system (6) and (7). The program was written and debugged in Fortran IV algorithmic language. The computations were made with a computer, and the results are presented in Figure 2.

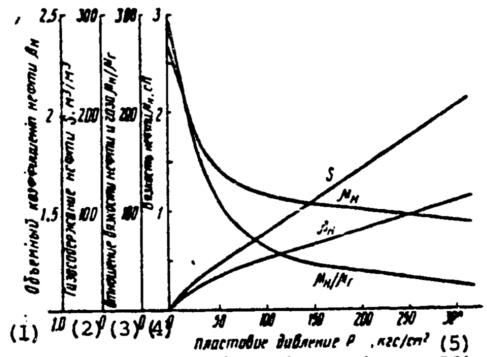

Figure 1. Dependence of Oil Volumetric Coefficient β_H, Gas Concentration of Oil S, Ratio of Oil and Gas Viscosities μ_H/μ_Γ, and Oil Viscosity μ_H on Bed Pressure P

Key:

1. Oil volumetric coefficient
2. Oil gas concentration
3. Ratio of oil and gas viscosities
4. Oil viscosity
5. Bed pressure

The developmental indicators for the formation were determined down to the minimum bed pressure, equal to 50 kg/cm^2, at which exploitation of the wells is still possible; a comparison of the computation results for the different variants is presented in the table below.

The hydrodynamic studies confirm the possibility for increasing the final oil ouput for flooded formations by switching them to a depletion system of development after the pressure method of development becomes unprofitable. As we can see from the table, the increment in oil output resulting from development of the formation with dissolved gas following cessation of flooding is 0.9-13.4 percent in the examined variants, and that it increases as the residual petroleum reserves increase.

Presence of free gas in the bed at the beginning of the period of secondary depletion causes a decrease in the amount of oil extracted additionally (variants I, II and III, IV). The suitability of preliminary depletion of the formation may be judged from a comparison of the oil output for variants II and V. The data presented here show that the payoff represented by an increase in the additional oil yield with depletion occurring toward the end

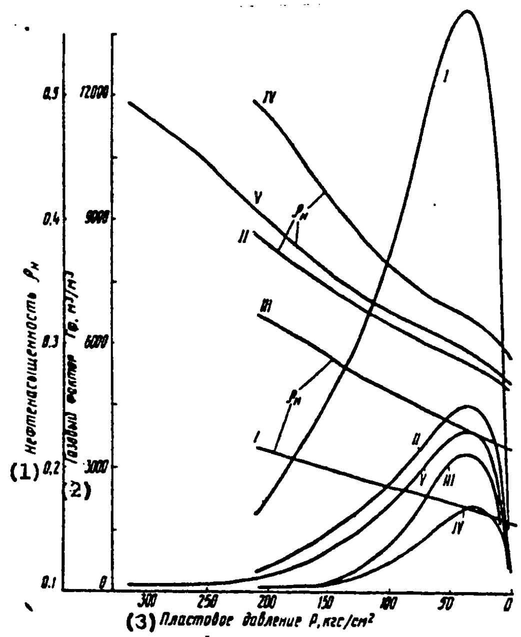

Figure 2. Dependence of Bed Pressure P, Oil Saturation ρ_H, and Gas Factor Γ_Φ in a Triphasal System Subjected to Depletion: I, II, III, IV, V--variants of development

Key:

1. Oil saturation level
2. Gas factor
3. Bed pressure

in the fifth variant is smaller than the payoff enjoyed due to reduction of bed pressure in the principal period--the final oil output in the fifth variant is 1.7 percent lower than in the second.

The maximum additional oil yield due to depletion development of the formation following cessation of water injection was enjoyed in the fourth variant, but in comparison with the other variants the oil output remained the lowest. It follows from this that for the development method examined here, the greatest volume of oil extraction should occur in the principal period of the formation's exploitation.

As we can see from the table, the final gas output is practically the same for all variants (81-85.6 percent). Differences in the conditions offered by the variants for development have a significant effect upon changes occurring in the gas factor (see Figure 2), which results in equal gas yield ratios.

(1) Показатели	(2) Варианты				
	I	II	III	IV	V
(3) Нефтеотдача в основной период разработки, %	70,5	47,1	55,5	32,2	39,1
(4) Добыча нефти при разработке на режиме истощения, млн. $м^3$	0,6	2,9	3,3	8,1	6,8
(5) Использование остаточных запасов нефти, %	3,2	9,0	12,1	19,8	18,5
(6) Конечная нефтеотдача, %	71,4	51,9	61,0	45,6	50,2
(7) Прирост нефтеотдачи, %	0,9	4,8	5,5	13,4	11,1
(8) Использование запасов газа в основной период разработки, %	59,0	43,1	69,7	53,8	39,0
(9) Добыча газа при разработке на режиме истощения, млн. $м^3$	3446	4912	2027	3571	5436
(10) Использование остаточных запасов газа, %	64,9	66,7	51,6	59,6	68,8
(11) Использование запасов газа, % . .	85,6	81,0	85,3	81,3	81,0
(12) Прирост газоотдачи, %	26,6	37,9	15,6	27,5	42,0

Key:
1. Indicators
2. Variants
3. Oil output for principal period of development, %
4. Oil yield with depletion development, millions m^3
5. Utilization of residual oil reserves, %
6. Final oil output,%
7. Increment in oil output, %
8. Utilization of gas reserves in principal period of development, %
9. Gas yield with depletion development, millions m^3
10. Utilization of residual gas reserves, %
11. Utilization of gas reserves, %
12. Increment in gas output, %

Thus development of the flooded beds first with dissolved gas and then by water flooding promotes a relatively high oil output even when such beds are exploited by a secondary depletion method.

The time a bed is exploited using water injection must be relatively long, so that a large quantity of petroleum could be extracted in the principal period, and free gas could be displaced from the bed, thus increasing the effectiveness of exploitation at the time of secondary depletion.

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FUELS

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LABORATORY INVESTIGATIONS INTO USE OF SLUDGE TO RAISE OIL OUTPUT

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 pp 13-15

[Article by M. F. Svishchev, G. B. Turbina, M. I. Pyatkov, A. S. Kasov, and Ye. A. Mikhaylova]

[Text] The wastes of industrial enterprises have been used successfully in petroleum industry. Thus, sludge has been used to raise the intake capacity of injection wells at the Tverskoye and Yakushkinskoye oilfields in Kuybyshevskaya Oblast. The Volgograd Scientific Research and Planning Institute of Petroleum Industry conducted research on the possibility of using sludge from the synthetic fatty acid shop of an oil refining combine as an oil displacing agent. The results of the experiment showed that under certain physicogeological conditions, injection of sludge into a bed may significantly raise the oil output and reduce the formation development time.

Sludge obtained as a waste product from oil additive production at the Omsk oil refinery was also subjected to research by the Siberian Scientific Research Institute of Petroleum Industry in order to broaden the raw material base for using physicochemical methods to raise the oil output of oilfields in West Siberia. When MSG-8 distillate oil is sulfonated by sulfur anhydride, we get oil-soluble sulfonic acid, which forms the additive. Part of the products resulting from sulfonation of condensed aromatic hydrocarbons and the resinification and oxidation products settle as sludge.

Under normal conditions sludge is a thick asphalt-like mass of dark color with the sharp odor of sulfur anhydride. It contains about 10 percent free sulfuric acid, 50-60 percent organic sulfonic acids, resinification and oxidation products (30-40 percent), and water.

Aqueous sludge solutions possess surfactant properties, a product of the high concentration of sulfonic acids.

Sludge dissolves well in fresh water to form transparent solutions at a concentration not exceeding 0.5 percent. In mineralized water, all sludge solutions are turbid; in this case when the sludge concentration is greater than 0.5 percent, and especially when the mixture is heated, the water and hydrocarbon fractions separate into layers. Formation of a precipitate is also possible.

Various reagents usually employed to stabilize colloidal and mycellar systems were tested as a means for preventing stratification and precipitation in response to interaction with mineralized water: low molecular weight alcohols, nonionogenic surfactants, and caustic soda. Low molecular weight fatty alcohols did not produce a positive impact. When a nonionogenic surfactant such as OKM (oxyethylated tallow oil) is added, stabilization of a 0.05 percent sludge solution was observed at a sludge:OKM ratio of 1:3. The best results were achieved with caustic soda. Clarification of solutions occurs at sludge:NaOH ratios as low as 5:1. Use of caustic soda or OKM surfactant together with sludge produces a synergetic effect. The surface tension of different solutions bounded by purified kerosene at 20°C is presented below.

Solution	Surface Tension at Boundary of Purified Kerosene, mN/m
0.05% sludge in distilled water	16
0.01 NaOH in distilled water	18
0.15% OKM in distilled water	12
0.05% sludge + 0.01% NaOH in Cenomanian water	13
0.05% sludge + 0.15% OKM in Cenomanian water	10

Caustic soda interacts to neutralize sludge, forming sodium sulfonate out of the sulfonic acids. In this case the medium's pH increases from 3.03 (for a 0.05 percent sludge solution) to 8.2 (0.05 percent sludge + 0.01 percent NaOH)--that is, neutralized sludge having a weakly alkaline reaction forms.

From the standpoint of solubility, surfactant properties, and process economy, it would be best to neutralize sludge with caustic soda at a sludge:NaOH ratio of 5:1. When sludge solutions are stabilized by OKM, 15 times more of it is required than caustic soda.

Therefore 0.06 percent neutralized sludge (0.05 percent sludge + 0.01 percent NaOH) was used to study oil displacing capability. This solution's dynamic adsorption was determined beforehand.

The neutralized sludge solution was filtered through a core sample from bed P of the Trekhozernoye oilfield; in this case the reagent's adsorption was $8.015 \cdot 10^{-4}$ kg/kg. According to the results, adsorption was $1.1 \cdot 10^{-4}$ and $3.9 \cdot 10^{-4}$ kg/kg for 1 and 5 percent sludge solutions respectively. Published data offer the following values for adsorption of anionic surfactants: for sodium sulfonate--$2.33 \cdot 10^{-4}$–$2.48 \cdot 10^{-4}$ kg/kg, for sodium alkylsulfate--$4.77 \cdot 10^{-4}$ kg/kg--that is, it is comparable to the adsorption value given for sludge from the Omsk petroleum refining combine.

Sludge displacement experiments were also performed with oil samples from the Vatinskoye, Ust'-Balykskoye, Zapadno-Surgutskoye, and Mamontovskoye oilfields.

(1) Месторождение	(2) Пласт	(3) Температура опыта, °C	(4) ПАВ	(5) Концентрация ПАВ, %	(6) Коэффициент вытеснения при закачке: (7) воды	(8) растворов ПАВ после воды
(9) Ватинское	$БВ_8$	88	НКГ (19)	0,06	0,686	0,732
	$АБ_{1-2}$	70		0,06	0,646	0,659
	$АБ_{1-2}$	70		0,06	0,633	0,655
(10) Усть-Балыкское	$БС_{1-3}$	67	НКГ	0,06	0,673	0,738
(11) Западно-Сургутское	$БС_{1-3}$	60	НКГ	0,06	0,656	0,692
	$БС_{1-3}$	60		0,06	0,610	0,634
	$БС_{10}$	67		0,06	0,645	0,690
(12) Мамонтовское	$БС_{10}$	76	НКГ	0,06	0,635	0,675
		76		0,06	0,693	0,742
(13) Трехозерное	П	30	ОП-10 (20)	0,05	0,480	0,507
(14) Тетерево-Мортымьинское	П	78	ОП-10	0,05	0,640	0,660
(15) Правдинское	$БС_6$	83	ОП-10	0,05	0,659	0,678
(11) Западно-Сургутское	$БС_1$	60	ОП-10	0,05	0,487	0,531
	$БС_{10}$	30	ОП-10	0,05	0,490	0,540
	$БС_1$	70	ОКМ	0,05	0,550	0,620
	$БС_1$	60	ОКМ	0,05	0,487	0,550
	$БС_{1-3}$	60	ОКМ+ +ТНФ (21)	0,10	0,620	0,661
(10) Усть-Балыкское	$БС_{10}$	30	ОКМ	0,05	0,416	0,481
	$БС_{10}$	30	ОП-10	0,05	0,416	0,448
	$БС_1$	30	ОП-10	0,05	0,525	0,600
(16) Северо-Покурское	$БВ_6$	30	ОП-10	0,05	0,573	0,579
(17) Самотлорское	$АВ_{2-3}$	30	ОП-10	0,05	0,575	0,592
	$АВ_{2-3}$	30	ОП-10	0,05	0,622	0,637
	$БВ_8$	30	ОП-10	0,05	0,424	0,427
	$БВ_8$	30	ОП-10	0,05	0,669	0,669
	$БВ_8$	30	ОП-10	0,05	0,538	0,546
	$БВ_8$	73	Дисолван 4411 (22)	0,05	0,617	0,651
(18) Советское	$АВ_1$	50	Дисолван 4411	0,05	0,702	0,720
		30	ОП-10	0,05	0,771	0,814

Key:

1. Deposit
2. Bed
3. Experiment temperature, °C
4. Surfactant
5. Surfactant concentration, %
6. Displacement factor with injection of:
7. Water
8. Surfactant solutions after water
9. Vatinskoye
10. Ust'-Balykskoye
11. Zapadno-Surgutskoye
12. Mamontovskoye
13. Trekhozernoye

[Key continued on following page]

14. Teterevo-Mortym'inskoye
15. Pravdinskoye
16. Severo-Pokurskoye
17. Samotlorskoye
18. Sovetskoye
19. Neutralized sludge
20. OP-10
21. Trisodium phosphate
22. Disolvan

Instead of oil from the beds, the research was formed on degasified oil mixed with kerosene in a proportion resulting in viscosity identical to that of bed oil at a temperature close to that of the bed. After cessation of the oil's displacement by water (Cenomanian, from the Vakh River, or a model of bed water), sludge solution was injected, which subsequently filtered through until the maximum water concentration of the extracted product was reached. From 2.04 to 11.02 pore volume equivalents of sludge were injected through porous mediums.

An analysis of the experimental results (see table) showed that in all experiments, continuation of sludge injection after water resulted in additional displacement of from 1.3 to 6.5 percent oil.

The best effect was achieved for beds BS_{1-3} of the Ust'-Balykskoye (6.5 percent) and BS_{10} of the Mamontovskoye (4 and 4.9 percent) oilfields, and the least was observed for bed AV_{1-2} of the Vatinskoye oilfield (1.3 and 2.2 percent). The reason for the difference in the effectiveness of displacement of oil by sludge solution in these experiments is apparently associated with individual properties of the oils and of the reservoir rock in the studied oilfields. The oil displacing capability of neutralized sludge solution is not inferior to that of aqueous solutions of surfactants such as OP-10, OKM, disolvan 4411, and trisodium phosphate.

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FUELS

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INCREASING FLUID EXTRACTION FROM WELLS OF UZEN' OILFIELD

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 pp 15-18

[Article by N. A. Malyshev and E. L. Leybin]

[Text] Exploitation data from 190 wells falling within the following groups were examined to determine the results of introducing forced fluid extraction for a 9-month period of exploitation: 1) 103 deep shaft wells converted from 56- to 68-mm pumps; 2) 20 deep shaft wells converted from 68- to 93-mm pumps; 3) 67 gas lift wells converted from 63.5- to 76.2-mm pump and compressor pipes.

In order to reveal the optimum conditions for increasing fluid extraction from the wells, the influence of geological and technological factors upon the magnitude and duration of the effect, as related to oil recovery, was analyzed.

An investigation was made of the influence exerted by intensification of fluid extraction, K_f (ratio between the mean fluid yield for the forced extraction period under analysis, $\bar{q}_f$, and the initial fluid yield, q_{f0}, prior to implementation of the geological and the technological measures), and the initial values of fluid water concentration, B_0, and fluid yield, q_{f0}. The geological factors studied included the influence of variations in the cross-sectional permeability of the well (the ratio of the maximum permeability of the i-th bed, $K_{max i}$, to the average permeability of the cross section, K_{ave}), variations in bed thickness (the ratio of the maximum effective thickness of the i-th bed, $h^{max}{}_{efi}$, to the total effective thickness, Σh_{ef}, of the exploited oilfield), in relation to the absolute value of maximum effective thickness of the i-th bed in the exploited oilfield and the specific degree of depletion of the reserves, α.

The obtained dependencies of relative growth in oil output K_o and the duration of the effect t_o on the degree of fluid extraction intensification K_f showed that these indicators do reveal distinct dependencies approaching linear. This attests to presence of a reserve for increasing fluid extraction from the wells.

Investigation of the dependence of parameter K_f on the initial fluid yield showed that for the 113 deep shaft wells (92 percent), the fluid yield of 10-50 tons per day was increased in the period of forced extraction by more than 1.4 times. This is what caused stable growth in petroleum output by an average of 4.6-4.9 tons per day per well. At the same time the short-term effect upon petroleum output for 51 gas lift wells (76.1 percent) with fluid yields of more than 100 tons per day can be explained by attainment of a sufficient degree of fluid extraction intensification (for this group of wells, K_f averaged 1.18).

The main cause of the low effectiveness of attempts at forcing fluid extraction lies in that the possibilities for reducing bottom hole pressure for a particular category of wells down to a projected level is limited due to the insufficient lift of deep-well pumps, and the low gas pressure employed in gas lift recovery. In order to insure stable fluid extraction at a volume greater than 150-200 tons per day from highly flooded wells ($B_0 > 50$ percent), we would have to solve the problem of using highly productive underground equipment, and raise gas pressure in the gas lift system. Otherwise forcing fluid extraction from this category of wells would not lead to positive results.

Analysis of the dependencies presented in Figure 1 would show that while the degree of forcing, K_f, is identical for wells with different initial water concentrations, B_0, the increase in oil output, K_o, differs. In this case the lower relative increments in oil yield are typical of wells subjected to greater flooding--that is, when wells with a high water concentration are subjected to forcing, more-intense fluid extraction should be planned. Using the obtained dependencies, it would seem possible to establish the lower limiting values of K^*_f, producing an increment in oil yield of $K_o > 1$, for wells exhibiting different degrees of flooding. As we could see from Figure 1, for wells with $B_0 < 50$ percent, $K_f^* > 1.2$-1.3, and for wells with $B_0 > 50$ percent, $K_f > 1.6$.

We can see from Figure 1 that the origin of the curves falls within the domain $K_o < 1$, $K_f < 1$. This is associated with the fact that the increase in fluid output (and all the more so of oil output) from the particular group of wells was not noted throughout the entire period of analysis. Therefore the averaged yields of fluid, $\bar{q}_f$, and oil, $\bar{q}_o$, in the analyzed period of forced exploitation were found to be lower than the initial yields prior to implementation of the geological and technological measures, and consequently the K_o and K_f values for these wells turned out to be less than 1.

Figure 2 shows the dependence of the influence of the duration of the effect upon oil yield, t_o, on technological (a,b) and geological (c,d,e) factors for different multiples of fluid extraction, K_f. The obtained dependencies indicate that all of the listed factors have an influence on the effect's duration, t_o. Investigation of these dependencies reveals that a greater duration of the effect in relation to oil yield results from the following values for geological and technological factors: when fluid yields are up

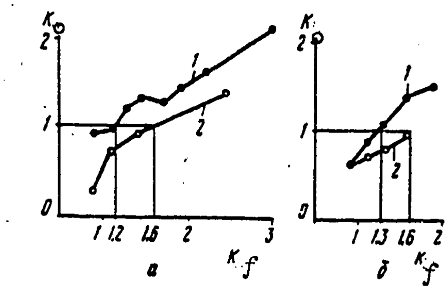

Figure 1. Dependence of Relative Increase in Oil Yield, K_o, on Degree of Fluid Extraction Intensification, K_f, for 123 Deep Shaft Wells in Groups 1 and 2 (a) and 67 Gas Lift Wells in Group 3 (b): 1--$B_0 < 50$ percent; 2--$B_o > 50$ percent

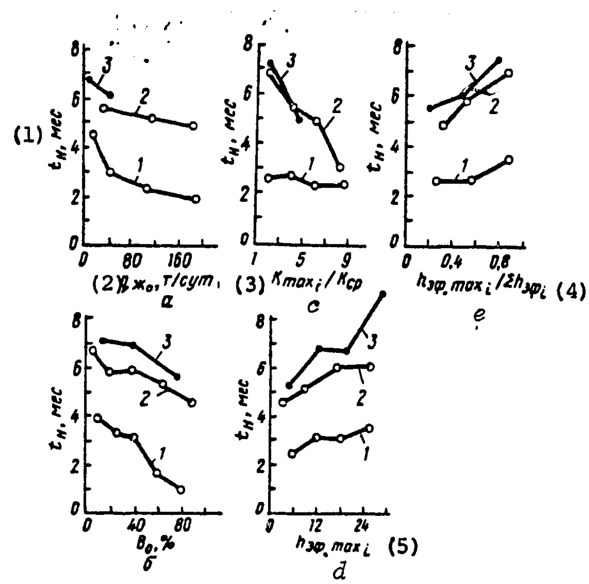

Figure 2. Dependence of the Duration of the Effect Upon Oil Yield, t_o, on Geological and Technological Factors in the Presence of Different Degrees of Fluid Extraction Intensification, K_f: 1--$K_f < 1.4$; 2--$K_f = 1.4$-2.0; 3--$K_f > 2.0$

Key:

1. t_o, months
2. q_{f_o}, tons per day
3. K_{max_i}/K_{ave}
4. $h_{ef.max_i}/\Sigma h_{ef.i}$
5. $h_{ef.max_i}$

to 50-70 tons per day (a); when the initial water concentration is up to 50 percent (b); when the nonuniformity of permeability is lower (c); when individual beds within the oilfield undergoing exploitation are thicker (d,e).

In addition we evaluated the effectiveness of geological and technological measures in relation to different groups of wells located in adjacent and subtending rows. We examined 103 deep shaft wells (group 1) and 67 gas lift wells (group 3). The results of the analysis are summarized in the table.

(1) Группа скважин, ряды	(2) Число скважин	(3) Параметры работы скважин до форсирования		(5) Достигнутая величина на $K_ж$, доли един.	(6) Продолжительность эффекта по нефти $t_н$, мес	(7) Прирост среднесуточного дебита на одну скважину, т	
		B_o, %	(4) $q_{жо}$, т/сут			(8) нефти	(9) воды
(10) *Глубиннонасосные скважины*							
(11) 1а, прилегающие	68	39	28	1,58	4,4	4,5	12,2
(12) 1б, стягивающие	35	22	29	1,45	5,7	4,9	9,0
(13) *Газлифтные скважины*							
(14) 3а, прилегающие	41	50	150	1,22	2,7	−3,5	36,2
(15) 3б, стягивающие	26	44	147	1,19	2,2	−7,1	40,9

Key:
1. Well group, rows
2. Number of wells
3. Well operating parameters prior to forcing
4. q_{f_0}, tons per day
5. Attained value of K_f, unit fractions
6. Effect duration in relation to oil, t_0, months
7. Increment in mean yield of a single well, tons
8. Oil
9. Water
10. Deep wells
11. 1a, adjacent
12. 1b, subtending
13. Gas lift wells
14. 3a, adjacent
15. 3b, subtending

As we can see, for deep shaft wells, the best effectiveness indicators are associated with well subgroup 1b in subtending rows. This can be explained by the fact that while the fluid yields were the same and the degrees of extraction intensification were relatively close (1.58 and 1.45) for subgroups 1a and 1b, the initial water concentration of wells of subgroup 1b turned out to be less than that in wells in subgroup 1a.

The effectiveness indicators were different for both subgroups of gas lift wells, which are characterized by close q_{f_o} and B_o parameters. The best results were noted for wells in adjacent rows. The better effectiveness of wells in subgroup 3a may be explained by a significant decrease in bottom hole pressure, which in the period of analysis declined by an average of 5 percent for subgroup 3a in comparison with the initial bottom hole pressure; it dropped by only 2 percent in relation to subgroup 3b.

Thus analysis of the effectiveness of measures aimed at forcing fluid extraction showed that an increase in oil yield is not achieved in all cases, and the duration of the effect upon oil yield is short for a significant proportion of the wells. Moreover the existing approach for selection of wells to be subjected to forced exploitation does not permit us to forecast the anticipated results.

On the basis of this analysis, the following order of selecting wells to be converted to forced exploitation is suggested.

1. The following geological and technological parameters are singled out for each well: yields of fluid q_{f_o} and oil q_{o_o}; water concentration B_o; bottom hole P_h and bed P_b pressure; the fluid productivity coefficient K_{prod}; gas saturation pressure in oil P_{sat}; parameters describing the heterogeneity of the exploited oilfield in relation to permeability and thickness, and the degree to which the well exploits the unit reserves.

2. Measures aimed at forcing fluid extraction should be implemented at wells operating with current bottom hole pressures above the projected level ($P^*_h = 0.75\ P_{sat}$), as approved by the integrated development plan.

3. The possible reserve for raising the current fluid yield is assessed:

$$\Delta q_f = K_{prod} \cdot \Delta P_{res}$$

where ΔP_{res} is the reserve for reduction of current bottom hole pressure to the projected level.

4. The predicted fluid yield, $\bar{q}_f$, obtained in response to reduction of current bottom hole pressure to the projected level, is determined:

$$\bar{q}_f = \bar{q}_{f_o} + \Delta q_f \, .$$

The obtained $\bar{q}_f$ should be evaluated from the standpoint of the technical possibilities of the available underground equipment for insuring fluid yields stabilized at level $\bar{q}_f$.

5. The predicted degree of fluid extraction intensification is determined:

$$\bar{K}_f = \bar{q}_f / q_{f_0}.$$

6. The empirical dependence (see Figure 1) for the predicted $\bar{K}_f$ corresponding to an initial water concentration B_0 is used to determine the predicted value of relative increase in oil yield, $\bar{K}_o$. In this case if $K_o > 1$, then forcing fluid in this well would increase the oil yield; however, if $K_o < 1$, it would not be sensible to take steps to raise fluid extraction from this well.

7. Using the empirical dependencies (see Figure 2) for the corresponding values of geological and technological parameters and the predicted $\bar{K}_f$, we evaluate the anticipated duration of the effect upon oil yields, t_o.

Thus considering the recommendations presented above, based on the results of generalizing facts for 190 wells, we can raise the effectiveness of measures aimed at forcing fluid extraction.

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FUELS

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ASPHALTIC-RESINOUS SUBSTANCES, PARAFFIN IN UDMURTNEFT' ASSOCIATION

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 pp 18-20

[Article by O. F. Lezov (deceased), Ya. L. Smirnov, F. A. Kamenshchikov, and I. N. Golovin]

[Text] Oil of the Udmurt oilfields can be characterized in terms of its physicochemical properties as heavy, having a density of 0.89-0.92 gm/cm^3; it has a high sulfur content (2.5-3.5 percent) and a high paraffin content (3.6-9.5 percent), and at ground level its viscosity is substantial, up to 160 cP. The total concentration of asphaltic-resinous substances and paraffin attains 75 percent. The gas concentration is insignificant--10-25 m^3/ton, and the concentration of nitrogen in oil gas is high--up to 80-90 percent. The saturation pressure of gas in oil is high, close to the initial bed pressure (96-112 kg/cm^2). The pour point of the oil varies from -4 to -17°C. The melting point of the paraffin is 48-57°C.

Wells are operated mainly on the basis of a mechanized method. Almost all production wells of the Udmurt oilfields were found to be subjected to intense deposition of resinous-paraffin formations since the beginning of their development.

Current repairs are associated to a significant extent with deparaffination of the wells. Moreover the wells also suffer significant periods of idleness due to clogging of pumping equipment by paraffin. Wells awaiting current repairs stand idle for about 20 days.

Various methods for dealing with deposits of paraffin and with asphaltic-resinous substances are being used and tested concurrently with operation of the oil wells: mechanical (scrapers, weights, sweeps, balls), thermal (processing wells with hot oil using an ADP-4-150 unit, and steam using a PPU-3M unit), chemical (use of various reagents with solvent properties), and preventive (use of pump and compressor pipes with glass-enamel coatings on their inner surfaces).

The effectiveness with which various methods of deparaffination are used, as determined from the time between cleanings, is shown below.

Form of Deparaffination	Period Between Cleanings, Days
Hot treatment of pump and compressor pipes coated with enamel	48-50
Hot rinsing of uncoated pump and compressor pipes	36-40
Processing with solvents	35-40
Processing with PAA solution	32-36
Glass-coated pump and compressor pipes	About 1 year

Because of the absence of a more-effective method, the thermal deparaffination method--that is, processing of the wells with hot oil or steam--has enjoyed the greatest acceptance at Udmurt oilfields. However, the interval between thermal treatments is relatively short. The reason for this obviously lies in the fact that the temperature and the depth to which heating occurs are insufficient. Research established that paraffin deposition occurs down to a depth of 500-600 meters; consequently the heating temperature at this depth must be close or equal to the melting point of paraffin (48-55°C). In heat treatment, unfortunately, the heating temperature (which starts at 100-110°C) drops to 60°C at a depth of just 50-80 meters, while at 150 meters it drops to 45°C. Consequently it is only within this interval that the resin-paraffin deposits could be melted and carried away with the current of fluid. Below this level, paraffin does not melt; it only softens and drains downward on the surface of pump and compressor pipes and hoses, thus increasing the thickness of paraffin deposits in the 250-400 meter interval, as can be deduced from deposit curves plotted for a number of wells. The more-viscous asphaltic-resinous compounds soften to a viscoelastic state; then they undergo aging, and it becomes even more difficult to remove them. Moreover they create more-favorable conditions for subsequent deposition of resinous substances and paraffin. The effectiveness of heat treatment depends in many ways on the volume of hot oil injected. Temperature measurements down to the lifting depth showed that injection of oil having a temperature at the well head of 98°C drops in temperature to 20°C at a depth of 300 meters when a 2 m^3 volume is used, to 30° with a volume of 10 m^3, and to 35°C with a volume of 25 m^3. This confirms the low effectiveness of processing wells with hot oil.

The wells are subjected to a significant amount of different types of treatment each year with the purposes of removing deposits of resinous substances and paraffin, or preventing their deposition (see below).

Treatment Type	Number of Treatments in 1978
Heat treatments with hot oil using an ADP-4-150 unit	3,971
Steaming wells with a PPU	3,300
Chemical reagents	1,037
Dropping rubber balls into delivery lines	5,449

Thus each operating well undergoes an annual average of seven rinsings and steamings, five deparaffinations of delivery lines, and one treatment with chemical reagents. In addition to these operations to remove paraffin from oil extraction equipment, pipes and hoses are steamed during current repairs of the wells. In 1978 current repairs were performed 3,096 times on wells of the "Udmurtneft'" Association.

As we can see from the data presented here, heat treatments are the principal method of deparaffination of oil extraction equipment. Because of the growth in the number of wells, the ADP-4-150 and PPU-3M units are unable to fully satisfy the growing demand for well deparaffination. When all wells must be treated in a single month, only 70 percent are actually subjected to treatment, as a result of which most of the remote wells are processed at an interval of 2-3 months, which leads to excessive unjustified periods of idleness between current repairs of the wells. The climatic conditions as well as the marshiness and roughness of the terrain significantly hinder timely thermal deparaffination of the wells and delivery lines.

It should be noted that the machine unit presently produced for well deparaffination, the 1ADP-4-150, is more effective than the PPU-3M. Moreover the Tatar ASSR Scientific Research and Institute of Petroleum Machine Building has developed a new modification of the machine unit, the 2ADP-2-150, which permits treatment of the wells in a unit-well-unit cycle. The new production cycle permitted by the 2ADP-2-150 unit reduces the need for conveying oil to the machine unit, raises the quality of well treatment, and decreases operating expenses.

Pump and compressor pipes with coated inner surfaces are used to control deposition of resinous substances and paraffin. Despite the fact that 90 percent of the wells are outfitted with pump and compressor types with an enamel coating, their effectiveness against tar, asphaltene, and paraffin deposits is low. Owing to them, the interval between cleanings increased by only 8-10 days. Moreover use of enamel-coated pump and compressor pipes complicates operation of the wells because such pipes do not permit acid treatment, required in the exploitation of carbonate reservoirs. Since May 1976 tests have been conducted on pump and compressor types with a glazed inner surface. Forty-six wells were outfitted with glazed pipe on 1 January 1979; of these, six are operated with sucker rod pumps, and 40 are operated with submersible centrifugal pumps.

The interval between repairs is an important indicator of well operation. While for wells outfitted with pump and compressor pipes with and without an enamel coating it is 130-135 days (for sucker rod pumps), for wells with glazed pipes it is twice longer. The need for heat treatment has been eliminated with introduction of glazed pump and compressor pipes. If we consider current repairs performed on wells not associated with deparaffination, the average period between cleanings and between repairs is about 305 days. The wells can operate without the use of any other deparaffination methods. Control inspections of pump and compressor pipes, performed by lowering a paraffin meter into the well, and inspections of the pipes during current repairs indicated absence of paraffin deposits on their surfaces; thus they were lowered back into the well without treatment and steaming.

A method for preventing deposition of asphaltic-resinous substances in pump and compressor pipes has enjoyed use at the Mishkinskoye oilfield: An aqueous polyacrylamide solution is periodically injected into spaces around the pipes of the wells. However, the methods currently employed for dealing with deposits of asphaltic-resinous substances and paraffin do not fully solve this problem.

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REMOVING REAGENTS OF SOLID HYDROCARBONS DEPOSITS, ASPHALTIC-RESINOUS SUBSTANCES

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 pp 20-22

[Article by V. V. Sizaya and A. A. Geybovich]

[Text] One of the promising ways for dealing with deposits of solid hydrocarbons and asphaltic-resinous substances formed on the walls of oilfield equipment when extracting, collecting, and transporting oil is to use various sorts of removing reagents. The action of such removers is based on partial dissolution or dispersion of deposits and their subsequent loosening, owing to which the deposits become mobile and are carried away with the flow of oil. Therefore when selecting the remover and the optimum conditions of its use, it would be important to study its solvent and dispersing capability in relation to the deposit.

Solid deposits are a rather complex mixture including oil, paraffin, tars, asphaltenes, petroleum, water, and mechanical impurities. Such deposits are dissolved as a rule by hydrocarbons of the methane and benzene series and their derivatives, which react with the deposits to form colored, opaque solutions. Therefore the commonly accepted method for determining solubility on the basis of solution saturation temperature cannot be used. Instead, solubility is determined by a "rod" method and a weight method. Ways for determining the effectiveness of reagent action upon paraffin deposits created in the laboratory are also known. However, these methods can be used only to arrive at a comparative description of the reagents.

Thus the "rod" method provides an evaluation of the action of reagents upon natural deposits of paraffin in static conditions. Structural changes occur in the deposits in this case, inasmuch as they settle on the metallic rod in melted form. The "cold plate" method provides an evaluation of the action of reagents in dynamic conditions upon paraffin deposits obtained in a laboratory from a model fluid or from petroleum. In this connection the need has arisen for developing a device permitting laboratory investigation of the effectiveness of removing reagents upon natural deposits of solid hydrocarbons and asphaltic-resinous substances in dynamic conditions.

Figure 1 shows a diagram of the device. It consists of walking beam head *4*, link gear levers *5*, and an electric motor and reduction gear *6*. Container *2*, which is a metallic net suspended from a collar, is suspended freely from the head of the walking beam by flexible thread *3*. The device is supplied with a set of nets with hole diameters of 0.1-0.5 mm.

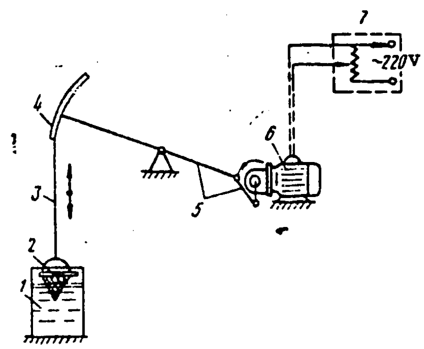

Figure 1. Device Used to Determine Effectiveness of Removing Reagents Upon Deposits of Solid Hydrocarbons and Alphaltic-Resinous Substances

During the device's operation, the container moves back and forth in the vertical plane, periodically submerging in the reagent solution, contained in vessel *1*. The speed of the container's movement is set with autotransformer *7*.

One gram of naturally deposited material is placed in the container, on the metallic net. The heat-resistant vessel is filled with 25 ml reagent. The ratio of the quantities of deposited material and reagent may be varied from 1:5 to 1:100 depending on the dimensions of the containers and the vessels. Experiment time is 30-120 minutes. To maintain the required temperature, the vessel and reagent are set up in a thermostatically controlled bath. After the experiment the residue on the metallic net and the dispersed fraction of the deposited material filtered out of the reagent are stored in a thermostat at 30-50°C until complete removal of volatile hydrocarbons, and then they are weighed with a precision of 0.01 gm. The solubility of the deposits in the reagent is computed with the formula

$$z = \frac{(m_1 - m_2 - m_3) \cdot 100}{m_1}$$

where z--solubility of deposits in reagent, percent; m_1--mass of deposit sample prior to contact with reagent, gm; m_2--mass of undissolved deposit residue in container following contact with reagent, gm; m_3--mass of deposit fraction dispersed in reagent, gm.

The research was conducted on paraffin deposit samples from oilfields of the "Nizhnevolzhskneft'" Association differing in their melting points and their concentrations of paraffin and asphaltic-resinous substances (Table 1).

Clear commercial petroleum products were used as reagents: gasoline, clarified kerosene, and petroleum solvent. The results of the experiments are shown in Table 2 and Figure 2.

Table 1

Deposit, Horizon, Well Number	Deposit Solidi-fication Point, °C	Concentration, %	
		Paraffin	Asphaltic-Resinous Substances
Zhirnovskoye, Tula, 86	64	46.5	6.6
Zhirnovskoye, Yevlano-Livenskiy, 604	76	64.6	3.6
Kamyshinskoye, Staro-Oskol'skiy, 96	75	65.4	1.6
Oleynikovskoye, 156	75	76*	5.9

*Concentration of paraffin-oil fraction

Comparative data were obtained on the effectiveness of reagent action upon different deposits (Table 2).

Thus petroleum solvent, which is a mixture of hydrocarbons in the benzene series, had the most effective action. As we can see from Table 2, paraffin deposits in well 86 are almost completely disintegrated in this reagent after 30 minutes. The solubility of deposits in petroleum solvent is 78 percent. It should be noted that deposits containing more than 60 percent paraffin and an insignificant quantity of asphaltic-resinous substances have lower solubility not only in gasoline and kerosene but also in petroleum solvent.

Paraffin deposits from well 156 were used as an example with which to determine the effectiveness of petroleum solvent depending on time of contact. It was established that to remove deposits similar to those obtained from well 156, the time the reagent is left in the oilfield equipment must not exceed 60-90 minutes (see Figure 2).

Table 2

(1) Номер скважины	(2) Реагент—удалитель отложений	(3) Режим опыта	(4) Количество отложений, %: (5) Нерастворимый остаток (на сите 0,5)	(6) диспергируемая часть в реагенте	(7) растворимая часть в реагенте
86	Бензин (8)	(11) Скорость 2,3 см/с; температура 20°С; продолжительность контактирования 30 мин; соотношение отложений и реагента 1:25	15	41	44
	Керосин (9)		7	58	35
	Нефтяной сольвент (10)		Отсут.	22	78
604	Бензин (8)		38	50	12
	Керосин (9)		27	65	8
	Нефтяной сольвент (10)		33	45	22
156	Бензин (8)		22	40	38
	Керосин (9)		18	48	34
	Нефтяной сольвент (10)		27	35	38
96	Нефтяной сольвент (10)		47	15	38

Key:
1. Well number
2. Deposit removing reagent
3. Experimental conditions
4. Deposit quantity, %
5. Insoluble residue (on 0.5 mesh seive)
6. Fraction dispersed in reagent
7. Fraction dissolved in reagent
8. Gasoline
9. Paraffin
10. Petroleum solvent
11. Rate--2.3 cm/sec; temperature--20°C; time of contact--30 minutes; ratio of deposits and reagents--1:25

Parallel determinations of the effectiveness of petroleum solvent and gasoline upon paraffin deposits from well 156 were made in order to evaluate the comparability of experiment results. Time of contact was 60 minutes, and rocking rate was 2.3 cm/sec (Table 3).

It follows from the data in Table 3 that the relative error in determination of the dispersing and dissolving properties of the reagent does not exceed 3 percent for three parallel measurements.

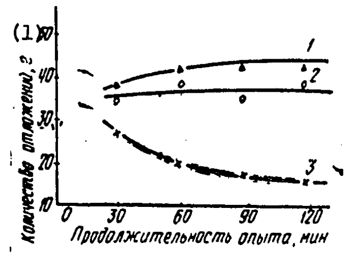

Figure 2. Effectiveness of Reagents Depending on Time of Contact With Deposits of Solid Hydrocarbons and Asphaltic-Resinous Substances: *1*--deposit soluble fraction (reagent's dissolving action); *2*--deposit dispersed fraction (reagent dispersing action); *3*--deposit insoluble fraction on metallic net

Key:
1. Deposit quantity, gm
2. Experiment time, minutes

Table 3

(1) Реагент—удалитель отложений	(2) Характер отложений после контакта с реагентом	(3) Количество отложений, %			(5) Абсолютная погрешность	(6) Относительная погрешность, %
		опыт № 1 (4)	опыт № 2	опыт № 3		
(7) Нефтяной сольвент	Нерастворимый остаток (на сите) (8)	20	20	21	0,44	2,18
	Диспергируемая часть в реагенте (9)	38	40	38	0,89	2,30
	Растворимая часть в реагенте (10)	42	40	41	1,0	2,43
(11) Бензин	Нерастворимый остаток (на сите) (8)	22	23	24	0,67	2,91
	Диспергируемая часть в реагенте (9)	27	28	27	0,44	1,60
	Растворимая часть в реагенте (10)	51	49	49	0,89	1,79

Key:
1. Deposit removing reagent
2. Nature of deposits following contact with reagent
3. Deposit quantity, %
4. Experiment number
5. Absolute error
6. Relative error, %
7. Petroleum solvent
8. Insoluble residue (on seive)
9. Dispersed fraction in reagent
10. Soluble fraction in reagent
11. Gasoline

Thus the method proposed here can be used to select an effective reagent with which to remove deposits of solid hydrocarbons and asphaltic-resinous substances in the concrete conditions of the particular oilfield, and to arrive at the optimum conditions of its use in dynamic conditions (temperature, time of contact, rocking rate).

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DEVELOPMENT OF PRODUCTIVE BEDS IN THE PRESENCE OF BARIUM OXIDE DEPOSITS

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 pp 22-24

[Article by V. I. Veshchezerov]

[Text] Beds C_{IV}, C_{III}, and C_{II} of the Radayevskiy horizon are confined to the Nizhnevezeyskiy terrigenic complex of the Mukhanovskoye oilfield in Kuybyshevskaya Oblast. In this case bed C_{IV} is subdivided by dense rock into intercalations C_{IVa} and C_{IVb}. The beds are composed of quartz sandstone nonuniformly interbedded by clayey aleurolites. The sandstone cement is basically clayey.

The beds are being developed all together by a single filtration system of wells, and they are the second object of exploitation. Since 1957 their exploitation involved perimeter and contour flooding with fresh water, and waste water has been used since 1972. Productive beds are being injected with waste water having a mineral content of 120-130 gm/liter and primary salinity of 66-68 %·equiv.

In the last 10 years of exploitation of the second object, we observed cases of precipitation of inorganic salts in production wells, pumping facilities, pump and compressor piping, delivery lines, and grouped measuring and separation devices.

Research established that sulfateless brine in the productive beds of the Radayevskiy horizon in the Mukhanovskoye oilfield contain barium. The concentration of barium in brine from bed C_{II}, undiluted by industrial waste water, is usually 150-250 mg/liter, while in brine from bed C_{IV} it reaches 400 mg/liter.

Barium-containing sulfateless brine is chemically incompatible with all other brine or by-product water containing heightened sulfate quantities. When they are mixed together, inorganic salts, represented mainly by barium oxide or barytocelestine, settle out as a precipitate. Under thermobaric conditions, barium and barytocelestine precipitate out at any point in the beds, wells, and production equipment where barium containing brine mixes with sulfate-containing water. In this case when the quantity of sulfates is sufficient, barium precipitates out completely, for example in a common flow of barium-containing by-product brine and sulfate water following their mixing at an SU-3.

Owing to the complex geological structure of productive beds in the Radayevskiy horizon and injection of fresh water into these beds, by-product water having diverse chemical composition formed within them. By-product water in certain sections of the central (domed) part of the structure, in the vicinity of wells 209, 210, 238, 239, 509, 368, and 261, is represented by deposit water or by weakly diluted deposit brine. Most of the production wells in the western and eastern periclinal parts of the structure are flooded by by-product water having lower mineral content. In this case the concentration of sulfates in by-product water increases to 500 mg/liter, and in some cases even up to 870 mg/liter (as deposit brine is diluted by fresh injected water). This process is associated with leaching out of cement sulfate minerals and their removal from the sandstone reservoirs.

Gradual displacement of water having lower mineral content and brine by waste water containing up to 490 mg/liter sulfates is observed in connection with a transition to pumping waste water into the central part of the structure from the northern and southern wings. Moreover owing to non-uniformity in flooding and in extracting the oil reserves with a single filtration system, the chemical composition of by-product water in different beds is not identical. Water of varying chemical composition occasionally enters the bottom holes of the production wells, which is why barium sulfate and barytocelestine precipitates form. The basic characteristics of the chemical composition of by-product brine and water in productive beds of the Radayevskiy horizon of the Mukhanovskoye oilfield are shown in the table below.

(1) Номер скважины	(2) Пласт	M	(3) Содержание, г/л: Ca^{2+}	Mg^{2+}	SO_4^{2-}	HCO_3^-	S_1, (4) %·экв.	Ba^{2+}, мг/л (5)
828	C_{IVa}	241,3	21,1	4,5	0,01	0,03	66,46	401
210	$C_{IVб}$	244,4	21,0	4,43	0,01	0,03	67,1	212
245	$C_{IVaб}$	62,0	5,2	0,85	0,16	0,31	69,54	—
285	C_{II-III}	145,7	12,8	2,13	0,24	0,07	68,12	8,0
834	C_{II}	75,4	4,0	1,46	0,52	0,40	75,72	—

Key:
1. Well number
2. Bed
3. Concentration, gm/liter
4. %·equiv
5. mg/liter

Two cases of complications may be examined as examples with which to both clarify the causes of salinity and monitor the status of the development and flooding of individual productive beds. For example, prior to July 1970 well 210 jointly exploited beds C_{II}, C_{III}, and C_{IVab}. It was shut down after almost complete flooding by mixed waters of low mineral content. Selective isolation of the incoming water currents revealed barium oxide deposits of significant thickness on the walls of the casing--in the interval from the filter to the pump intake (2,225-1,150 meters)--and, further up, in the UETsN [not further identified] and the pump and compressor pipes. Following shut-off of the upper highly flooded beds by two packers, well 210 was converted for exploitation of just intercalation C_{IVb}. At a fluid yield of 510 m^3/day, well 210 is flooded exclusively by the influx of weakly diluted barium-containing sulfateless brine from intercalation C_{IVb}. Salt formation was not observed.

Exploitation of bed C_{IVab} by well 828 was also accompanied by intense formation of barium oxide and barytocelestine deposits in UETsN, pump and compressor pipes, and the delivery line. Due to formation of dense and hard barium oxide deposits on the intake screen, the working wheels, and the guides of the ETsN [electric centrifugal pump], the device jammed 5-15 working days following start-up. During this period, water of mixed composition entered well 828.

Due to a significant concentration of calcium in the water, an attempt to pump a compound inhibiting deposition of solid adhering salt deposits was unsuccessful.

The lower intercalation C_{IVb}, which is flooded by diluted by-product water having a high sulfate concentration, was shut off after the research. Well 828 began operating with a fluid yield of 145 m^3/day having a water concentration of 36 percent, and it began producing weakly diluted by-product brine. Moreover the barium concentration in the brine increased to 401 mg/liter, while the sulfate concentration dropped to 12 mg/liter. Complications in the work of the UETsN were not observed.

In addition, the operations carried out with wells 210 and 828 also indicate differences in the nature of flooding of the bed in the same section of the structure. Examining, in general, the flooding of productive beds in exploitation object II, flooding of production wells, and the causes of complications created in the extraction and collection of oil associated with precipitation of hard sticky barium oxide deposits, we would have to make a differentiated evaluation of the barium oxide formation phenomenon. Precipitation of barium oxide in production wells, pump equipment, delivery lines, GZU [not further identified], and in the oil collection and initial preparation systems is a negative phenomenon causing a great deal of economic loss in oil extraction. This phenomenon must be fought, and mainly by separating the currents of chemically incompatible barium -containing and sulfate-containing water and brine. Considering the conditions resulting from differences in the chemical composition of by-product brine and water, we must immediately test and begin industrial use of chemical reagents preventing formation of sticky deposits of inorganic salts and barium oxide.

Precipitation of barium oxide deposits out of true solutions in flooded laminae and in flushed zones of the productive bed must be interpreted as a positive phenomenon, raising the effectiveness of artificial flooding, and the final oil output. What this essentially means is that when the chemical composition of by-product water takes shape and intermixing occurs between barium-containing brine and artificially formed sulfate water, barium precipitates out in the form of barium oxide or barytocelestine, partially or completely, right within the reservoirs of the productive beds.

Data describing the chemical composition of by-product water and the results of monitoring the technical condition of wells and oil extraction equipment confirm the presence of this process. Absence of barium in by-product water and, additionally, formation of salt in the tested wells are direct evidence of the existence of these processes.

Artificical salt deposition in the beds is proceeding spontaneously, since problems associated with the chemical compatibility of the water and possible complications in exploitation were not examined in the planning stage or in previous years of exploitation of the productive beds of the Radayevskiy horizon.

Use of fresh hydrocarbonated water to maintain reservoir pressure in the first stages of development should be noted as a positive point. Under the geological and hydrogeological conditions of the productive beds in the Radayevskiy horizon of Mukhanovskoye oilfield, saturation of artificially formed by-product water by sulfates depends on the concentration of sulfate minerals in the rock of the reservoir, and it proceeds irregularly and relatively slowly. Therefore precipitation of barium oxide in large, highly tangible quantities occurs in remote zones of the bed, over relatively large areas of the artificially flooded zone. This is confirmed by the slow injectivity of the injection wells. On the other hand when production wells flooded with barium containing by-product brine--sulfate-containing water--are plugged, barium precipitates out right within the critical zone of the bed. A similar effect can also be achieved with the reverse combination of the chemical composition of by-product water and plugging water. In such cases well productivity significantly drops after plugging, and development often must proceed over a long time interval.

Thus the phenomenon of chemical incompatibility of brine and water of different compositions, which is accompanied by deposition of barium oxide and barytocelestine, yields to monitoring and control, and it may be capitalized upon as a technically performable process by which to raise the effectiveness of artificial flooding and the final oil output. Moreover deposition of salts in wells and production equipment is almost completely excluded, which minimizes the need for special operations with various chemical reagents.

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FUELS

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PROBLEMS OF EXPLOITING OILFIELDS IN COMPLEX CONDITIONS

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 pp 25-28

[Article by V. P. Maksimov]

[Text] The experience of organizing oil extraction in West Siberia and western Kazakh SSR has produced a number of important, complex scientific-technical problems, and it has persuaded us of the need and the economic feasibility of finding fundamentally new concepts upon which to base all operations. These problems are unique, and they are associated to a significant extent with the unusual conditions under which the oilfields must be developed, ones hindering attainment of the end goal--fuller extraction of oil from the bed.

Complex conditions may be an objectively existing natural factor, or they may arise as a result of man's interference. The former include unfavorable geological and climatic conditions, inaccessibility to transportation, the temperature of the reservoir system (up to 80°C), the broad range of petroleum properties (0.6-150 cP within the beds), presence of carbon dioxide in the reservoir system, and so on. The second group includes complications stemming from crookedness of the wells, high rates of oil extraction and growth in water concentration of well discharge, disturbance of the carbonate equilibrium in the reservoir system resulting from injection of incompatible water and, as a consequence, deposition of salt in production equipment, and so on. These complications are fully or partially typical of oilfields in West Siberia, the western Kazakh SSR, and other oil extraction regions.

This aggregate of complicating factors has not been studied sufficiently in relation to oil extraction. Determination of the basic problems of exploiting Siberian oilfields, which is the most general and complex case, has important significance, since it would permit us to concentrate the resources and efforts of specialists at finding the most effective concept for developing the region and the sector. In this case it would be important to emphasize that in looking for long-range alternative solutions to problems, the criteria we use include not only the conventionally employed economic indicators but also minimum labor outlays.

Information of particular accuracy and completeness lies at the basis of any evaluations made of different processes and decisions arrived at in relation to all elements of the oil extraction system. Growth in the accuracy and dependability of information is a general trend typical of all sectors of science.

The noted peculiarities of the oilfields do not permit us to effectively acquire the raw information we need by traditional methods. Great complexities arise in the transition to mechanized exploitation of wells, which dramatically complicates communication between the wellhead and the bottom hole. A need arises for seeking new ways to acquire information.

One of the basic parameters of current control over oilfield development is reservoir pressure. Its measurement in the field is associated with certain methodological and organizational difficulties, and this is why we are interested in finding quick methods for determining reservoir pressure, particularly when the pressure recovery curve is incomplete.

The VNII [All Union Scientific Research Institute of Petroleum and Gas] has developed amethod based on using an identification model of the reservoir-well system. It boils down to measuring changes in bottom hole pressure particular time intervals after shut-down of the well, and determination of correlations.

The results from treating data acquired in research on wells of the Salymskoye oilfield indicated a possibility for predicting reservoir pressure with an error of 1-2 percent of the true value. The identification method is also useable in determining the productivity factor. This method also essentially involves creation of a model of the reservoir and determination of its parameters. The determination error does not exceed 5-10 percent.

A group of colleagues of the VNII have developed a method for determining current reservoir pressure without shutting down a well to take the measurements, based on statistical differentiation of the dependencies of yields and bottom hole pressure as a function of time. The possible error does not exceed 3-4 percent in this case.

Significant complexities arise in determination of hydrodynamic parameters when oilfields are placed into production. Arisal of perturbations within the bed owing to the start-up and shut-down of wells hinders acquisition of good results by conventional methods. This problem can be solved by using the analytical method developed by the Siberian Scientific Research Institute of Petroleum Industry.

Current production information serves as the raw data for determining the hydro- and piezoconductivity of the reservoir and the productivity factor of the wells: the schedule of well operation, the initial and current reservoir pressure, and the time of well shut-down for measurement of current reservoir pressure. Using the method of successive approximations, we can determine accurate values for the sought parameters; in this case the difference in values in comparison with the results of standard analyses is about 10 percent. This method can also be used to determine the scope of the reservoirs, and to reveal the hydrodynamic relationships existing between different beds.

There are extensive possibilities for fuller analysis of the peculiarities of production processes in the use of simulation models. As we know, most analysis methods produce information on parameters only in relation to a concrete point of a formation, but if we are to control these processes, we would have to know integral values characterizing the object--a bed for example--as a whole. The usual way of obtaining such information--analyzing data from the largest possible number of wells--is associated with significant outlays. Another way is to build a simulation model that adequately reflects the real object. It has been established that the Monte Carlo sampling method is an effective modeling tool, since it permits us to integrally determine parameters using a rather small sample.

This problem is also associated with another important task--early diagnosis. If we can achieve it, we would be able to evaluate the possible consequences of the particular technological concept employed, or of errors made in determining parameters when the quantity of information is insufficient.

This task may be completed with operational diagnosis methods developed by the VNII, based on mutual correlation analysis of the degree of interaction occurring, using data from normal well exploitation as the basis. These methods were developed in application to influences exerted upon the bottom hole zone of the reservoir, combustion within the reservoir, and so on.

This task requires comparison of two samples, one of which corresponds to use of a conventional system (flooding for example), and the other of which corresponds to application of some particular method (for example raising the oil output) and establishing the actual influence of the latter.

Change in well water content, in the gas factor, and so on is used as the diagnostic indicator for different processes.

The second group of problems involves peculiarities in the physicochemical properties of reservoir systems.

We know that the completeness with which oil is extracted from a porous medium depends on many factors--the viscosity and composition of the petroleum, the viscosity of the displacing agent, interphasal tension, the properties of the surface of the porous medium, and so on. These factors influence the choice and effectiveness of methods for raising the oil output of the beds.

A mutual relationship exists between the reservoir oil output and the use coefficient of the oil-saturated stratum. An analysis would show that this coefficient is significantly greater than unity. Filtration of the drilling solution worsens the collecting properties of the reservoir's critical zone and reduces the coefficient of hydrodynamic efficiency to 0.5-0.8. This reduces the energy indicators of the exploitation processes of production and injection wells.

The VNII evaluated the collecting properties of the bottom hole and remote zones of beds worked by production wells in the Samotlor and Ust'-Balyk oilfields. It was established that due to imperfections in the well finishing techniques and penetration of filtrate into the bed, the permeability of a significant part of the critical zone (with a radius of up to 6-14 meters) is more than twice lower than in the bed's remote area. The productivity of the wells may be increased by 25 percent and more, on the condition that permeability is restored to its initial value.

The physicochemical aspects of the problem of raising reservoir oil output are associated with capitalization upon the properties of the surface of pore channels. It has been established for example that in the Salymskoye oilfield, which has a hydrophobic reservoir, liberation of gas within the reservoir creates an additional pressure gradient that prevents flow of oil to the well. Under these conditions hydrophilization of the surface would promote elimination of this effect and an increase in oil output.

Petroleum from some oilfields, Russkoye for example, is typified by non-Newtonian properties, with relaxation time attaining several hours. The presence of relaxation effects must be accounted for not only when evaluating filtration processes but also when determining the conditions under which deep-well pumping equipment must operate. It has been established that this permits us to determine the optimum pump delivery rate depending on the product of the number of oscillations and piston stroke.

Also of special significance are processes associated with conventional flooding of beds. We know that underground water is being used to increase pressure in productive beds for the first time in domestic practice in the oilfields of Siberia. The volume of water injected annually attains more than 60 million m^3. The operational experience of using Aptian-Cenomanian water has special value, and it must be laid at the basis of the analysis in support of subsequent solutions. This water has the best oil flushing and filtration properties.

The main advantage of underground water lies in the fact that its use precludes or significantly reduces the danger of arisal of two complex scientific-technical problems--deposition of salt in production wells and in the oil collection and preparation system, and sulfate reduction in oil beds. In a number of cases these problems are the main causes of a short interval of well operation between repairs, and they make additional operational expenditures necessary.

Meanwhile the experience acquired in development of the Zapadno-Surgutskoye oilfield and individual sections of the Ust'-Balyk and Megionskoye oilfields, where water from underground sources was injected, shows that problems associated with deposition of salts and arisal of sulfate-reducing bacteria are absent here, or their importance is significantly reduced. A highly effective, simple procedure has been developed for the use of underground water; it produces a significant economic impact.

If we are to broaden the scale of its industrial application, we would have to once again return to the problem of using underground water. We must concentrate the efforts of scientists and specialists upon solving priority problems, such as increasing the unit output of water intake wells to 10,000 m^3/day and higher without sand removal, and at creating dependable technical resources for collecting and injecting underground water possessing better operational parameters.

The next group of problems is associated with the production aspect of creating and operating the basic operational systems (wells, and systems for collecting and preparing oil, gas, and water).

One of the important problems is development of oilfields with the help of inclined and horizontal wells, which makes it possible to significantly increase the drainage zone and raise the effectiveness of reservoir flooding. The experience of their operation and the computations show that the yield increases in this case, isolated sections of the bed begin producing, and the oil output rises. Research has also shown that when oilfields are tapped by horizontal wells of considerable length, oil extraction rises in the waterless period.

An analysis of inclined wells exploiting bed AV_{4-5} of the Samotlor oilfield and bed BV_6 of the Pravdinskoye oilfield showed that in these cases the productivity factor rises, this growth being proportional to the angle of incline of the shaft, within a range of up to 30°. It would not be difficult to evaluate the accompanying advantages: higher bottom hole pressure and, consequently, a longer period of natural flow, reduction of unit gas consumption in gas lift extraction, reduction of the depth to which the pump needs to be lowered, and so on.

Implementation of this method is associated with solution of a number of technical and organizational problems associated with drilling the wells, casing formation, development, and control and adjustment of the operations.

The fourth group of problems is associated with well exploitation.

The central problem that must be solved in well exploitation is that of reducing the number of personnel required. This would be possible only if we employ more-reliable methods and resources for raising fluids, ones significantly reducing the volume of repair operations that must be performed at the site of the well.

Experience has confirmed the high effectiveness of using the gas lift method, and it will doubtlessly by introduced on an increasing scale. In particular, evidence of this can be seen in the experience of gas lift exploitation of the Pravdinskoye oilfield.

Extensive use of the gas lift oil extraction method does not preclude the need for developing pump exploitation of wells. Application of deep-well pumps produces a number of complex scientific-technical problems associated with raising the effectiveness of oil extraction by pumps. These problems must be solved for the Siberian oilfields, mainly because of the relatively short time of operation of deep wells between repairs, resulting in higher losses in oil extraction and significant consumption of materials and manpower. As the number of mechanized wells increases, the problem of increasing the period of operation of pump wells between repairs becomes increasingly more acute.

The main causes of the large number of repairs required by the wells include deposition of salts, removal of sand from the critical zone of the bed, significant curvature of the beds, high fluid temperature, and so on.

The main tasks that must be completed through the efforts of oil specialists include, first of all, organization of control over the operation of equipment, and creation of a quality control service. Only a detailed, factual analysis of the causes behind equipment breakdowns will permit us to plan ways to eliminate them.

The experience of the "Bashneft'" Association shows that implementation of such measures can produce a significant impact.

It appears possible to increase the time of operation of pump wells between repairs by about 1.5 times in the next few years in response to just these measures alone. Specialists, mainly of the Central Scientific Research Institute of Petroleum Industry, will have to assume technical leadership over the control and selection of equipment to be provided to each well, over the operation of the equipment in accordance with the operating instructions, and over the collection and analysis of equipment dependability statistics.

Another important direction is to create and use more-effective pumping equipment. The sector is presently doing work in this direction. New types of pumps are undergoing tests in the laboratory and in the field. The task in this case is to create devices that could operate in a well for 2-3 years without the need for raising the pipe. One of them--a long-stroke deep-well pump--is undergoing testing in the "Orenburgneft'" Association. Its specifications are significantly different from those of the normal series of rocking pumps. The estimated time of current repairs is decreased from 17 to 1-2 hours, and the need for an underground repair team and lifting apparatus is excluded. The annual economic impact enjoyed from its use is estimated at 3,000-5,000 rubles per well per year.

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USE OF ULTRASONIC METHOD TO DEAL WITH SALT DEPOSITION AT SAMOTLOR OILFIELD

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 pp 28-30

[Article by V. V. Dryagin, S. A. Yefimova, V. N. Makarov, L. N. Makarova, and G. N. Yagodov]

[Text] Development and exploitation of the Samotlor oilfield is complicated by deposition of salt in production equipment and at the well bottom hole.

Chemical methods, which require large amounts of chemicals and which are not always effective, are extensively employed today to control salt deposition.

Creation of methods to suppress salt deposition by means of powerful physical fields, acoustic in particular, is a promising direction. Physicochemical analysis of salt deposition products will be an aid in evaluating the possibilities and features of the method. It was with this goal that about 20 samples of salt deposits were analyzed. Phasal X-ray analysis (the Debye-Sherrer method) demonstrates that salt deposits in the oilfields of West Siberia are represented mainly by calcite (trigonal syngony) or barite (rhombic syngony).

A complete chemical analysis of the samples would show presence of small quantities of Na, K, Mg, Mn, and Fe salts.

Spectrometric analysis reveals boron, titanium, and other elements, the concentrations of which in the salt deposits are shown below, percent:

B	0,0008	Si	0,23
Ti	0,036	Al	0,15
V	0,0016	Fe	1,2
Mn	0,086	Ca	24,0
Co	0,005	Na	4,0
Cu	0,0003	K	2,0
		Mg	1,0
Ba	0,3	Mn	1,0

The multiple composition of samples correlates well with the chemical composition of injected reservoir fluid and with the composition of rock leaching products.

Microscopic analysis of salt slides indicates a dependence between salt deposition and the state and properties of pipe surfaces.

Various factors eliciting salt deposition (change in temperature, pressure, and the concentration of dissolved substances and carbon dioxide, the complex chemical composition of the deposits, and the state of pipe surfaces) indicates that salt deposition could be controlled suitably with the use of physical fields affecting the conditions of pipe-fluid contact. The results of testing the influence of sound in the laboratory and in the field demonstrated its effectiveness in controlling salt deposition. However, the series-produced ultrasonic apparatus employed is not well suited to the conditions offered by the oil-bearing regions of West Siberia.

In this connection it became necessary to develop a complex of apparatus intended for operation at low temperatures and in the presence of vibrations, and which would insure dependable work within a broad range of variable frequencies and output capacities. Such a complex was created for the first time as a result of joint work by the Siberian Scientific Research Institute of Petroleum Industry, the VNIIYaGT [not further identified], and the Ural Polytechnical Institute.

The acoustic apparatus includes a ground ultrasonic oscillator and a broad-band well acoustic emitter.

The figure below shows a block diagram of the acoustic apparatus. Ult..sonic oscillator *1* consists of a TPRCh-10-10-30 adjustable-frequency thyristor oscillator, *3*, having an efficiency of 0.7. The specifications of the ultrasonic operator are presented below:

Adjustable power, kw	
Consumed	up to 19
Output	up to 12
Adjustable frequency (in continuous mode) kHz	10-30
Pulse duration (in pulsed mode), sec	0.1-2
Overall dimensions, meters	1.7×0.7×1.5
Weight, kg	600

A GAZ-66 truck carries the ground apparatus. The oscillator's operation is monitored by apparatus represented by *4*,*5*,*6*, and *7*. A special device, *2*, is foreseen to match the oscillator with the well acoustic emitter *11* and cable *10*.

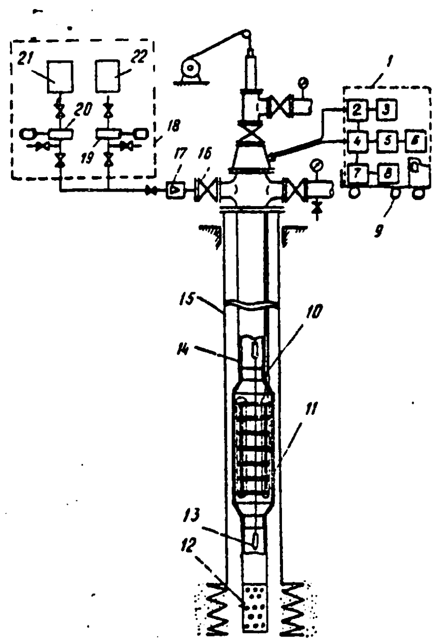

Diagram of Field Experiment With Test Well No 4643: *1*--ground ultrasonic oscillator; *2*--matching device; *3*--TPR4-10-10-30 thyristor converter; *4*--input filter block; *5*--measuring amplifier; *6*--acoustic parameter recorder; *7*--broad-band amplifier; *8*--frequency spectrum analyzer; *9*--GAZ-66 truck; *10*--KRBK cable; *11*--well acoustic emitter; *12*--NKT [pump and compressor pipes] intake filter; *13*--metallic monitoring cylinder; *14*--NKT; *15*--test well; *16*--slide valve; *17*--reflux valve; *18*--model fluid preparation block; *19*,*20*--dosing pumps; *21*,*22*--concentrated $NaHCO_3$ and $CaCl_2$ solution containers, respectively

Magnetostriction converters are used as the acoustic emitters. The emitters are made from magnetostriction strips, and they consist of a set of cylinders coiled along the generatrix. The metal housing containing the emitters has an exchangeable stem by which the emitters are lowered by NKT or a cable. The well emitter is powered by a KRBK-3×16 cable attached to the NKT by belts.

On the ground, the apparatus produces cavitational emissions in the entire range of operating frequencies, 10-30 kHz. The average acoustic pressure generated by the acoustic converter at a ranç of 1 meter is 40 kPa.

This apparatus was tested in test well 4643 at the Samotlor oilfield (see figure). The test well includes well *15*, model fluid preparation block *18*, and acoustic emitter block *1*. Acoustic emitters *11* are built into NKT *14* 200 meters from intake filter *12*. This test well can be used to model fluids with different concentrations of salts, and to create different thermodynamic conditions at the bottom hole.

The model fluid preparation block includes two containers *21,22* with a volume of 5 m^3 each, containing concentrated $NaHCO_3$ and $CaCl_2$ respectively.

Preparations to inject the model fluid into the well proceed according to the scheme presented below: The needed doses of $NaHCO_3$ and $CaCl_2$ solutions are fed by dosing pumps *19,20* into the injection pipeline, where they are mixed with water. Passing out of the pipeline through reflux valve *17* and slide valve *16*, the model fluid is fed to NKT filter *12* through the space around the pipes. In this zone, the fluid mixes with reservoir oil, and it rises up the NKT due to natural gas lift. The resulting water-oil emulsion passes through acoustic emitter *11*, where it is subjected to the action of the acoustic field.

Reagent dosing is monitored periodically by briefly closing the movable valves of the dosing pumps and measuring pump delivery. Mineralization of the model fluid is monitored during its injection on the basis of samples taken from the injection line.

The following procedure was used in the well experiment. Metal monitoring cylinders *13* were situated in the well, above and below the emitters. For 15 days the fluid in the well was subjected to acoustic energy of a particular frequency. Then the monitoring cylinders were raised to the surface, and the thickness of salt deposits was measured. Next the frequency of acoustic emission was measured, and the experiment was repeated.

The research was conducted at three different frequencies with the same emission intensity. As a control, cylinders were stored for 15 days under the same conditions but in the absence of the acoustic field. The experimental research was conducted for 4 months of trouble-free operation of the appartus. The results are compared in the table below.

Acoustic Field Frequency, kHz	Acoustic Field Intensity, kPa	Ratio of Deposit Thickness Before/After Acoustic Influence, mm/mm	Deposit	Well Yield Tons/Day
8	40	0.6/0		50
16	42	0.8/0	Calcite	40
22	42	0.7/0.1		30

These data show that the acoustic field reduces the thickness of salt deposits and increases well yield. The optimum effect occurs in a frequency range of 8-16 kHz, and at a significant acoustic field intensity. The nature of the deposits (calcite) is not a limiting factor of the acoustic influence.

Change in salt structure should also be noted: Following acoustic influence, the crystals have smaller dimensions, and they are bonded to the surface of the cylinder much more weakly than when the influence is absent.

These data can be explained in the following way: The acoustic field creates acoustic currents at hard surfaces, which break up centers of crystallization, and thus small crystals are removed from surfaces and carried away by the fluid.

The research results attest to the good efficiency of the apparatus, and the high effectiveness of using an acoustic field to deal with salt deposition.

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APPEARANCE OF IRON SULPHIDES, FREE HYDROGEN SULPHIDE IN FLUIDS FROM DEVONIAN WELLS

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 -- 31-33

[Article by Ye. O. Nedoboyeva]

[Text] In the initial period of perimeter flooding (1948-1949), underground water of the river Ik was subjected to extensive chemical processing--chlorination, decarbonization, deoxygenation, and so on.

Beginning in 1950, the water was injected into the bed without chemical processing, adding up to 25 percent surface water of the river Ik.

According to data of the Tatar ASSR Scientific Research and Planning Institute of Petroleum Industry (1960), sulfate-reducing bacteria (SRB) were discovered in surface water of the river Ik, but they were not detected in underground water. A mixture of surface and underground water from the river Ik was pumped out by KNS [compressor and pumping station] No 1, 2, 4, 5, 6, and 13. From June 1959 to September 1960 water from the river Ik was not used for this purpose. Injection wells 1301, 1299, 717, 1466, 551, and 553 of the logging series are fed by KNS No 5. Injection of mixed fresh water was started with well 717 in March 1958, well 1301 in April, and well 1299 in June. During the time that underground water to which surface water from the river Ik was not added was being injected, wells 1466, 551, and 553 were placed into operation.

Water pumped out of swabbing injection wells was analyzed in 1960. Iron sulfides and free hydrogen sulfide wells detected in water samples from wells 4, 357, 379, 717, 936, 1299, and 1301.

Middle and lower Devonian water does not contain hydrogen sulfide, but it does contain ionized ferrous iron at a concentration of up to 200 mg/liter. Hydrogen sulfide was formed in the bed due to the vital activity of SRB pumped in from the river Ik's surface water; entering into reaction with iron contained in the water and the pipes, the SRB produced iron sulfide.

Table 1 contains data on the work of the injection wells, and the water analysis results.

Similar analyses were conducted for injection wells 334, 815, 1034, 1274, 1334, 1401, and 1456; neither free hydrogen sulfide nor sulfur bound in the form of iron sulfides ~~was~~ detected in discharged water.

We can see from Table 1 that presence of iron sulfide and hydrogen sulfide in withdrawn water is observed only a year and more after injection of fresh water containing SRB.

Free hydrogen sulfide was discovered for the first time in oil emulsion from production well 683 (TsDN-4) in 1966 (at an 85 percent concentration of water having a density of 1.01 gm/cm^3).

In 1971, free hydrogen sulfide was detected in oil emulsion samples from the wells shown in Table 2.

Table 1

Таблица 1

(1) Номер скважины	(2) Дата вступления в эксплуатацию	(3) Приемистость, м³/сут	(4) Время работы скважины до исследования, мес	(5) Закачка воды до выявления зараженности	(6) Содержание сероводорода, мг/л
4	20/II 1958 г.	80	20	197840	14
717	16/III 1959 г.	400	13	132970	—
936	20/XII 1955 г.	80	60	—	—
1025	30/IX 1958 г.	190	31	—	20
1299	2/VI 1959 г.	880	18	450000	—
1301	18/IV 1959 г.	330	12	80000	8
1466	5/XI 1959 г.	400	11	—	—

Key:
1. Well number
2. Date placed into operation
3. Injectivity, m^3/day
4. Time of well operation prior to analysis, months
5. Amount of water injected prior to SRB detection
6. Hydrogen sulfide concentration, mg/liter

In 1970, periodic interruptions in oil preparation processes were observed at oil preparation facilities No 1, 3, and 5. Analysis of oil samples from the facilities, of fluid from the reservoirs and settling tanks, and of drain water from stage I and II settling tanks established that the samples of water and oil contain a large quantity of mechanical impurities consisting of small crystals of iron sulfide deposits together with oil adsorbed to their surfaces. A laboratory procedure was used to separate the precipitate out of the oil emulsion and to determine the quantitative composition of iron sulfide in it. The results are shown in Table 3.

Table 2

Well Number	Water Density, gm/cm^3	Free Hydrogen Sulfide Concentration, mg/liter
684	1.005	17
536	1.003	8
864	1.01	9
1136	1.005	15

Table 3

(1) Место отбора проб дренажной воды	(2) Содержание, мг/л		
	сульфидов железа (3)	механических примесей (4)	нефтепродуктов (5)
(6) Из отстойников I ступени	402	10736	6551
	78	976	3492
	440	2356	8871
(7) Из отстойников II ступени	1868	—	—
	64	788	1251
	740	5928	12320
	13	140	587

Key:
1. Place of drain water sampling
2. Concentration, mg/liter
3. Iron sulfides
4. Mechanical impurities
5. Petroleum products
6. From stage I settling tanks
7. From stage II settling tanks

We can see from Table 3 that as the concentration of iron sulfides in drain water increases, the concentration of petroleum products rises. Iron sulfides in settling tanks are contained in an intermediate layer--at the oil-water interface. Iron sulfides are stable emulsifying agents, and they actively corrode oil extraction equipment.

During 1971 the laboratory of physicochemical analysis of the TsNIPR [not further identified] analyzed the chemical composition of water from fluid samples taken from oil wells, and it additionally determined the concentration of iron sulfide in the samples.

Iron sulfides in samples of oil emulsions from Devonian wells exploiting beds not containing hydrogen sulfide had a concentration from 0.1 to 0.82 mg/liter fluid, and from 1 to 5.6 mg/liter oil emulsion. The quantity of sulfide in fluid from carboniferous wells exploiting beds containing hydrogen sulfide varied from 24 to 63 mg/liter, while their concentration in oil emulsion was from 122 to 220 mg/liter. The concentration of iron sulfide in extracted fluid was determined on the basis of data from 959 Devonian oil wells, and presence of iron sulfides was detected in 161 of these wells.

Fluids from Devonian wells belonging to oil extraction shops No 3 and 4 were analyzed in 1977. Bed D_1 was exploited by 343 wells that delivered a product containing water.

Iron sulfides were detected in 54 wells operating with injected fresh water.

Iron sulfides were detected in fluids from 17 wells operating with injected waste water.

Water samples from every flooded oil well of the "Tuymazaneft'" NGDU [not further identified] are subjected to chemical analysis each year. Tables 4 and 5 shows change in water mineral content and the concentration of water in oil from wells in which free hydrogen sulfide was detected.

Table 4

(1) Дата отбора пробы	(2) Плотность воды, г/см³	(3) Содержание воды за декабрь, %	(4) Дебит нефти, т/сут	(5) Содержание: (6) сероводорода	(7) сульфидов железа
22/X 1963 г.	1,06	38	—	—	—
8/X 1964 г.	1,04	65	—	—	—
13/IV 1965 г.	1,02	83	—	—	—
14/IX 1966 г.	1,01	84	—	Обнаружено (8)	—
28/III 1967 г.	1,01	87	—	»	—
15/III 1968 г.	1,01	83	22,6	—	—
16/VIII 1969 г.	1,02	83	21,6	—	—
18/IX 1970 г.	1,026	77	35,3	—	—
5/IV 1971 г.	1,031	81	24,7	Не обнаружено (9)	Обнаружено
26/XII 1972 г.	1,046	87	19,5	»	»
19/VI 1973 г.	1,056	92	14,7	»	»
4/V 1974 г.	1,04	92	7,0	»	»
4/VIII 1975 г.	1,025	94	10,5	»	»
19/XII 1976 г.	1,038	96	7,6	»	»
27/XII 1978 г.	1,048	97	4,1		Не обнаружено

Key:

1. Sampling date
2. Water density, gm/cm^3
3. Water concentration in December, %
4. Oil yield, tons/day
5. Concentration
6. Hydrogen sulfides
7. Iron sulfides
8. Detected
9. None detected

Table 5

Дата отбора пробы (1)	Плотность воды, г/см³ (2)	Содержание воды в декабре i-го года (3)	Дебит нефти, т/сут (4)	Содержание (5): сероводорода (6)	Содержание (5): сульфидов железа (7)
8/III 1962 г.	1,15	83	—	—	—
26/XII 1963 г.	1,07	81	—	—	—
29/III 1965 г.	1,06	В консервации (10)			
13/IX 1971 г.	1,01	98	2,5	Обнаружено (8)	Обнаружено (8)
17/VI 1972 г.	1,02	99	0,01	»	»
8/VIII 1973 г.	1,03	Ожидание текущего ремонта (11)			
24/I 1974 г.	1,04	98	3,8	Не обнаружено	Обнаружено
19/IV 1975 г.	1,06	97	9,1	» (9)	» (8)
2/VII 1976 г.	1,04	98	5,5	»	»
2/I 1978 г.	1,05	99	2,3	»	Не обнаружено (9)

Key:
1. Sampling date
2. Water density, gm/cm³
3. Water concentration in December of i-th year
4. Oil yield, tons/day
5. Concentration
6. Hydrogen sulfides
7. Iron sulfides
8. Detected
9. None detected
10. Undergoing corrosion-proofing
11. Awaiting current repairs

Well 683 went into operation in 1955, producing waterless petroleum. After 8 years of operation well 683 began to be flooded quickly by a mixture of reservoir water and injected fresh water. Change in mineral content of the water over the years of operation, the concentration of water in December of each year, the oil output, and the presence of iron sulfides and hydrogen sulfide are shown in Table 4.

Well 864 went into operation on 5 July 1953, producing waterless petroleum. Beginning in 1962 it was flooded by a mixture of Devonian water and injected fresh water. Change in mineral concentration of the water over the years of operation is shown in Table 5.

The density of Devonian reservoir water is 1.19 gm/cm³. As injected fresh water encroaches, water mineral content decreases in the oil wells, while encroachment of injected petroleum refining waste water (density 1.1 gm/cm³) causes water mineralization to increase once again.

The example of wells 683, 864, and others shows that as waste water approaches freshened water at the oil wells, free hydrogen sulfide and iron sulfide are not detected for some time in the water, after which iron sulfides once again appear in oil emulsion samples.

Table 6

(1) Дата отбора пробы	(2) Плотность воды, г/см³	(3) Содержание воды за XII i-го года	(4) Дебит нефти, т/сут	(5) Содержание (6) сероводорода	(7) сульфидов железа
2/III 1967 г.	1,165	26*	—	—	—
26/IX 1967 г.	1,12	75	—	—	—
12/V 1968 г.	1,06	87	46	—	—
29/IV 1969 г.	1,015	98	10	—	—
8/V 1970 г.	1,002	95	10	—	—
13/IX 1971 г.	1,005	97	8	15,0	Обнаружено (8)
20/IX 1972 г.	1,004	95	18	Обнаружено (8)	»
21/VIII 1973 г.	1,001	98	6,6	»	»
28/III 1974 г.	1,005	94	4,2	»	»
17/I 1975 г.	1,005	92	5,7	»	»
19/II 1976 г.	1,005	96	4,4	»	»
10/XII 1977 г.	1,002	98	3,8	»	»

*Water detected in March.

Key:
1. Sampling date
2. Water density, gm/cm^3
3. Water concentration in December of i-th year
4. Oil yield, tons/day
5. Concentration
6. Hydrogen sulfides
7. Iron sulfides
8. Detected

Well 1163 went into operation on 30 April 1954, producing waterless petroleum. In 1967 it began to be flooded by a mixture of Devonian water and injected fresh water. Change in water mineral content is shown in Table 6.

Free hydrogen sulfide and iron sulfides were detected in fluid extracted by well 1163. The concentration of sulfite ions in the water decreases rapidly from 575 mg/liter (1972) to 159 mg/liter (1976), which indicates occurrence of oxidation-reduction processes in the bed due to the vital activities of sulfate-reducing bacteria.

During 1978 free hydrogen sulfide was subjected to quantitative analysis in gases at the outlet of the KSSU-1.3, in which Devonian oil is subjected to separation, and in compressor stations (KS) No 5 and 10, where gas is sorbed from Devonian oil by oil extraction shops No 3 and 4.

Hydrogen sulfide was detected at quantities of 9.4 gm/100 m^3 gas at the KSSU-3 (oil extraction shop No 3), 0.7 gm/100 m^3 gas at KSSU-1, 6.5 gm//100 m^3 at KS-10, and 3 gm/100 m^3 gas at KS-5. Thirteen grouped devices of oil extraction shop No 3 were analyzed. Free hydrogen sulfide was detected in gas from Devonian wells 1163, 1165, 1216, 857, 855, 776, and 1555.

Heightened corrosiveness of petroleum refining waste water and frequent ruptures of water pipelines have been noted in recent years; this is apparently associated with presence of SRB in the water, and of sulfurous compounds--products of bacterial contamination of the oilfield.

11004
CSO: 8144/1367

FUELS

UDC 622.276.8

METHODS FOR DEHYDRATING, DESALINIZING OIL FROM GEORGIAN SSR OILFIELDS

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 pp 34-35

[Article by R. K. Khabibulina]

[Text] Oil from the Samgori and Teleti oilfields forms poorly stable, readily decomposable emulsions; this is why demulsification studies were conducted with 9:1 mixtures of such oil. Dehydration and desalinization were performed thermochemically in one stage in a laboratory demulsifying device. Emulsion models were prepared from waterless oil and reservoir water. In all experiments, the initial oil mixture contains 10 percent water and 798 mg/liter salts.

Oil mixtures from the Samgori and Teleti oilfields can be completely dehydrated and desalinized by the laboratory device down to trace quantities of salts (2-4 mg/liter) in a single thermochemical step at a temperature of 40-50°C; settling time is 2 hours, and demulsifier consumption is 10 gm/ton (Table 1).

At the oilfield, demulsification can be performed in a field reservoir without heating, since the oil temperature at the well mouth is 70-80°C. The oil mixture passes through mother liquor beneath a layer of reservoir water, and then it is settled for 2-4 hours. The demulsifier (10 gm/ton) should be fed into the oil line closer to the wells. Oil prepared in this fashion can be sent for refining without additional processing.

Thermochemical and electric processing methods involving one and two stages at a temperature of 80°C and a demulsifier consumption rate of 100-200 gm/ton were used to dehydrate and desalinize oil from the Supsa oilfield, which is distinguished by high emulsion stability. The experiments were conducted in the laboratory with a natural emulsion containing 20 percent water and 12,540 mg/liter salts (Table 2).

When the oil was processed in a single stage by the thermochemical method, where the demulsifier consumption rate was 200 gm/ton and settling time was 2 hours, the water concentration of the oil was 0.29 percent and salt concentration was 286 mg/liter. Two-stage processing by the same method (demulsifier

Table 1

(1) Номер опыта	(2) Добавка дсэмульгатора (дисолван 4411), г/т	(3) Температура, °C			(7) Качество обработанной нефти*	
		(4) ввода деэмульгатора в нефть	(5) промывки нефти через слой воды	(6) отстоя	(8) обводненности, %	(9) содержание солей, мг/л
1	0	30	30	30	0,4	122
2	10	30	30	30	—	11
3	20	30	30	30	—	2
4	0	40	40	40	0,36	88
5	10	40	40	40	—	3
6	20	40	40	40	—	2
7	0	50	50	50	0,2	26
8	10	50	50	50	—	2
9	20	50	50	50	—	1,5

* Quality of oil after 2 and 4 hours of settling was the same.

Key:

1. Experiment number
2. Amount demulsifier (Disolvan 4411), added, gm/ton
3. Temperature, °C
4. At which demulsifier was added to oil
5. At which oil as washed through water layer
6. Of settling
7. Quality of processed oil*
8. Water concentration, %
9. Salt concentration, mg/liter

consumption--200 gm/ton) decreased the salt concentration in the oil by approximately a factor of 2 (122 mg/liter); however, the water concentration of the oil increased to 1.08 percent due to emulsification of the rinsing water.

With combined processing (where the first stage was thermochemical and the second was electric), the oil contained 0.26 percent water and 100 mg/liter salts (see Table 2, experiment No 3).

More-extensive preparation of the oil (resulting in a salt concentration of 5-7 mg/liter) can be achieved by the electric method, which involves two stages and a demulsifier consumption rate of 20-30 mg/liter (see Table 2, experiments No 6, 7). Oil with an initial salt concentration of about 100 mg/liter can be prepared in this way in electric desalinizing NPZ (ELOU) devices.

Thus oil from the Samgori and Teleti oilfields may be brought to the required condition in a single thermochemical stage at a temperature of 40-50°C with a demulsifier consumption rate of 10 gm/ton. Oil from the Supsa oilfield can be prepared and delivered to petroleum refineries in the

Table 2

(1) Номер опыта	(2) Качество исходной нефти: (3) обводненность, %	(2) Качество исходной нефти: (4) содержание солей, мг/л	(5) Добавка: (6) деэмульгатора (дисолван 4411), г/т	(5) Добавка: (7) воды, %	(8) Ступень, метод обработки	(9) Время отстоя, ч	(10) Качество обработанной нефти: (11) обводненность, %	(10) Качество обработанной нефти: (12) содержание солей, мг/л
1	20	12540	100	—	I, термохимический (13)	2	—	—
			—	10	II, электрический (14)	1	0,36	236
2			150	—	I, термохимический	2	—	—
			—	10	II, электрический	1	0,32	198
3			200	—	I, термохимический	2	—	—
			—	10	II, электрический	1	0,26	100
4	0,26	100	20	5	I, термохимический	2	0,30	72
			—	10	II, электрический	1	—	18
5			30	5	I, термохимический	2	0,24	56
			—	10	II, электрический	1	—	12
6			20	5	I, электрический	1	0,12	48
			—	10	II, электрический	1	—	7
7			30	5	I, электрический	1	0,12	36
			—	10	II, электрический	1	—	5

Key:
1. Experiment number
2. Crude oil quality
3. Water concentration, %
4. Salt concentration, mg/liter
5. Additives
6. Demulsifier (Disolvan 4411), gm/ton
7. Water, %
8. Processing stage, method
9. Settling time, hr
10. Processed oil quality
11. Water concentration, %
12. Salt concentration, mg/liter
13. Thermochemical
14. Electric

group 1 quality category (water concentration--0.5 percent, salt concentration--100 mg/liter) after its processing by the combined method in two stages (the first stage being thermochemical and the second electric). More-extensive preparation of the oil, resulting in a salt concentration of 5-7 mg/liter, can be achieved with an ELOU and at a refinery in two electric stages under the following optimum conditions: temperature--80°C, electric field gradient--2.5 kv/cm, demulsifier consumption--20-30 gm/ton, consumption of rinsing water in stages I and II--5 and 10 percent respectively.

11004
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FUELS

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HYDRODYNAMIC CHARACTERISTICS OF BASIC SETTLERS USING A RADIOACTIVE ISOTOPE

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 pp 35-37

[Article by I. N. Yeremin, R. I. Mansurov, L. A. Pelevin (deceased), G. K. Alpatov, and A. Ye. Pripisnov]

[Text] A modeling device was used to develop the most sensible design of horizontal- and vertical-flow settlers. Industrial models of OGD-200 and OVD-200 apparatus were installed at the UPN-8 of the "Yuganskneft'" NGDU [not further identified]. Flow structure in settling tanks was studied in the first stage using the radioactive isotope Br^{82}. Figures 1, 2, and 3 are diagrams of the apparatus, the location of γ-emission sensors, and the distribution of oil flows at a productivity of 200 m^3/hr.

The quantity of labeled oil (which was proportional to the area of the response curves), recorded by the appropriate sensors, is arbitrarily expressed in figures 1, 2, and 3 by the length of the segments extending from the corresponding sensors. The peaks of the segments are connected to each other by a line conditionally representing the front of flow in the apparatus.

Despite the great area of the longitudinal section of an OVD-200 settling tank, oil moves relatively uniformly along the apparatus (see the curves above points *9-16* in Figure 1).

A certain degree of irregularity may be elicited by inexact apparatus productivity (the distributors are intended for a productivity of 300 m^3/hr), by insufficient density of the ascending flow (sparse positioning of openings and distributing pipes), the proximity of the phase separation boundary, and the perturbations it experiences in response to ascending emulsion flows. As the oil moves upward, the flows equalize and the front of oil movement approaches a straight line (see the curves above points *5-8* in Figure 1). In general the distributing devices support sufficiently uniform distribution of flows in relation to the longitudinal section of the apparatus. (The sensors at points *1-4* were the least sensitive, and they failed to record passage of labeled oil due to the low triggering activity of the isotope.)

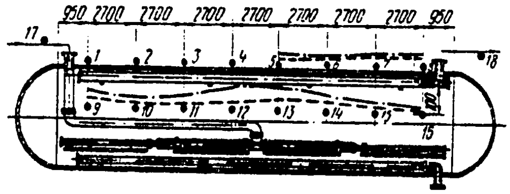

Figure 1. OVD-200 Settling Tank

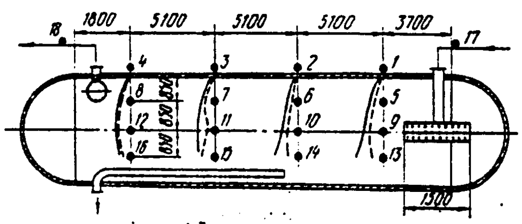

Figure 2. OGD-200 Settling Tank

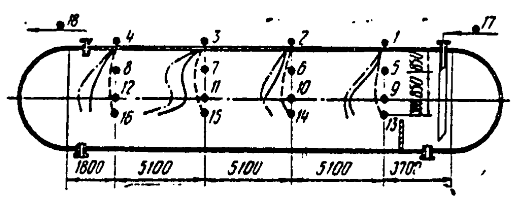

Figure 3. SibNIINP Settling Tank

An analysis of curves obtained for the OGD-200 settling tank (see Figure 2) would show that the highest rate of flow persists in the central and lower parts of the settling tank. In one experiment it was greater in the middle part of the settling tank in the first 10 meters of the apparatus' length, while in another experiment it was higher in the lower part--that is, at the water-oil interface. However, these differences are insignificant. As the flow moves further--that is, in the second half of the tank, the flow rates even out. Sensors in the upper part of the settling tank did not record γ-emissions due to the low triggering activity of the isotope and the lower sensitivity of the sensors. This does not mean that no movement occurred there; it is simply somewhat slower than in the middle part of the apparatus. In general the front of the flow in the OGD-200 is relatively flat throughout the entire length of the settling tank. It may be assumed that the intake device "quenches" the energy of the flow well and distributes it with sufficient uniformness throughout the cross section of the settling tank.

The nature of oil movement in the SibNIINP settling tank is about the same as in the OGD-200 settling tank (see Figure 3), but the front of the flow is much steeper. The contents are observed to flow through by the shortest path--from the top of the dividing wall to the outlet.

Weak movement of oil is observed in the lower part of the settling tank at the water-oil interface in the vicinity of sensors No 15 and 16. In 18 hours, an intermediate layer 200-250 mm thick and 2-3 mm long that accumulated there moved only 5 meters (from sensor No 15 to sensor No 16), though the flow rate in the front part of the settling tank at the water-oil interface was a good deal greater. This layer was detected by a portable SRP-2 radiometer, and it apparently consisted of an unbroken emulsion and mechanical impurities that adsorbed the isotope, since it exhibited high activity throughout this time.

Figure 4 shows response curves obtained at the outlets of the three settling tanks analyzed. For convenience in comparing the work of the settling tanks, relative values of τ, which represent the ratio between the actually measured time t and the theoretical time oil is present in the apparatus T, obtained with a consideration for the position of the interface, are plotted on the abscissa. Table 1 shows the results of analyzing the response curves.

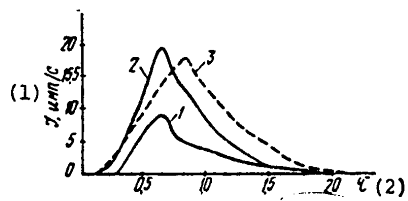

Figure 4. Response Curves at the Outlets of OGD-200 (*1*), SibNIINP (*2*), and OVD-200 (*3*) Settling Tanks

Key:

1. τ, Pulses/sec
2. Hours

Analysis of the obtained data (see Figure 4 and Table 1) established that the SibNIINP settling tank has somewhat worse hydrodynamic characteristics, especially t_{Π} for the leading front. Isotope is first detected after 7 minutes, which is 15 percent of the theoretical time of the oil's presence in the apparatus T, while in the OGD-200 the isotope appears after 15 minutes (30 percent of the theoretical time).

The maximum flow rate v_{Π} in the SibNIINP settling tank is 2.28 times greater than in the OGD-200. In this case the area of the "live" cross section of the oil current in this settling tank is only 1.14 times smaller than in the OGD-200. This great discrepancy may be explained mainly by the difference

Table 1

(1) Отстойники	(2) Производительность, $м^3/ч$	(3) Уровень воды, м	(4) Фактические значения времени, мин			(5) Приведенные значения $\tau = t_i / T$			(6) Скорость, см/с		
			$t_п$	$t_м$	$t_с$	$\tau_п$	$\tau_м$	$\tau_с$	$v_п$	$v_м$	$v_т$
(7) СибНИИНП	200	1,0	7	30	34,8	0,15	0,66	0,76	4,75	1,11	0,79
(8) ОГД-200	200	0,6	16	36	36,8	0,30	0,68	0,70	2,08	0,92	0,69
(9) ОВД-200	200	1,3	6	33	33,4	0,15	0,85	0,86	0,58	0,11	0,08

Note: $t_П$--moment at which isotope first appears at apparatus outlet; $t_М$--time of maximum isotope concentration at apparatus outlet; $t_с = \frac{\sum_{t_п}^{t_\infty} C_i t_i}{\sum_{t_п}^{t_\infty} C_i}$ --mean time oil is present in apparatus; T--theoretical time of fluid present; $v_П$--maximum flow rate; $v_М$--mean rate of direct flow; $v_Т$--mean theoretical flow rate.

Key:
1. Settling tanks
2. Discharge, m^3/hr
3. Water level, meters
4. Actual time values, min
5. Reduced $\tau = t_i/T$
6. Rate, cm/sec
7. SibNIINP
8. OGD-200
9. OVD-200

Table 2

Таблица 2

(1) Исследуемые аппараты	(2) Производительность, $м^3/ч$	(3) Основные гидродинамические параметры		
		$\tau_п$	$\tau_т$	$\tau_с$
(4) Электродегидратор 1ЭГ-160	200	0,05	0,40	0,70
(5) Отстойник ОГ-200 конструкции КБ объединения «Саратовнефтегаз»	230	0,14	0,45	0,78
(6) Отстойник конструкции ОВД-200	200	0,15	0,85	0,86

Key:
1. Apparatus analyzed
2. Discharge, m^3/hr
3. Basic hydrodynamic parameters
4. 1EG-160 electrodehydrator
5. OG-200 settling tank designed by "Saratovneftegaz" Association Design Office
6. OVD-200 settling tank

in the effectiveness with which the input devices operate--that is, their capability for absorbing the kinetic energy of the incoming flow and distributing it uniformly over the cross section of the apparatus. The difference in the times of appearance of maximum isotope concentrations is insignificant--2 percent. The average rate of movement of oil flowing straight through the SibNIINP settling tank is 40 percent higher than the calculated rate, while in the OGD-200 it is 33 percent higher. It should be noted that the volume use coefficient ν_C for the SibNIINP settling tank is 6 percent higher than for the OGD-200, mainly because of the lower volume of oil present in the apparatus (owing to a high water level), and consequently smaller circulating eddy currents.

An almost symmetrical curve was obtained at the outlet of the OVD-200 settling tank, typified by vertical current movement (see Figure 4), which indicates good distribution of the emulsion along the length of the settling tank. The time of arisal of maximum isotope concentration at the outlet of the OVD-200 is 85 percent of the theoretical time. The settling tank contains few dead zones, about 7 percent of the volume. The volume use coefficient for the apparatus is 86 percent, which is 10-16 percent higher than for settling tanks in which the current moves horizontally.

To permit comparison of the work of the OVD-200 with that of other apparatus of similar construction, Table 2 shows the basic hydrodynamic parameters of the 1EG-160 electrodehydrator and the OG-200 settling tank, designed by the "Saratovneftegaz" Association Design Office, analyzed earlier.

We can see from Table 2 that the OVD-200 settling tank doubtlessly holds the advantage: For it, the time of arisal of maximum concentration is almost twice greater, which is close to the theoretical time of presence. The volume use coefficient is also higher.

Thus in comparison with other apparatus of similar design and settling tanks in which the current moves horizontally, the OVD-200 settling tank, in which the flow is vertical, is hydrodynamically superior. Of the two horizontal-flow settling tanks studied, the OGD-200 holds a certain advantage in its hydrodynamic characteristics.

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FUELS

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USE OF OIL-SOLUBLE DEMULSIFIERS IN FORM OF PETROLEUM SOLUTIONS

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 pp 38-39

[Article by Ye. V. Miroshnichenko, T. I. Fedorishchev, A. S. Feliksov, and S. F. Chernavskikh]

[Text] A procedure for using oil-soluble demulsifiers in the form of petroleum solutions has been introduced at the Zapadno-Surgutskiy and Ust'-Balykskiy consumer centers. The oil is prepared in two stages, using an identical procedure. Figure 1 illustrates the process employed by the TKhU-2 and TKhU-3 systems of the Zapadno-Surgutskiy consumer center.

Hydrated oil from the oilfield is degassed in the final separation stage. Before the final separation stage, first a minimum quantity of demulsifier and then hot drain water is introduced into the oil flow. The partially broken down emulsion is piped into crude storage reservoirs, where it is separated into petroleum and water. Partially dehydrated oil is fed by crude pumps into heaters (the bulk of the demulsifier is added before the pumps). The heated oil then passes into an emulsion breakdown unit. Before reaching the emulsion breakdown unit, a certain quantity of water from the first dehydration stage is added to the flow of oil. After undergoing final breakdown, the emulsion is placed into settling tanks, in which it is separated into commercial oil and water.

Devices created by the "Surgutneft'" and "Yuganskneft'" NGDU [Petroleum and Gas Extraction Administration] to prepare and dose the working reagent solution (UPR) are similar, and they consist of a centrifugal mixing pump with a low delivery volume, a piston dosing pump for the undiluted reagent, an oil pipeline, a water pipeline, and reagent pipelines with flow meters installed (see Figure 1, 8). The characteristics of UPR apparatus are presented in Table 1.

The working oil solution of demulsifiers is prepared in the following fashion. Dehydrated oil flows by gravity from the settling tanks to the intake of the centrifugal mixing pump, and undiluted reagent is fed in from the reagent receiving tank by the dosing piston pump. The ratio between

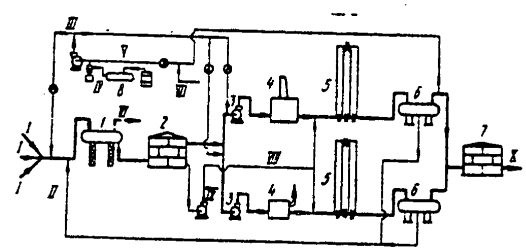

Figure 1. Process Diagram for the TKhU-2 and TKhU-3 Systems of the Zapadno-Surgutskiy consumer center: *1*--the final separation unit; *2*--crude reservoir; *3*--crude pump; *4*--heater; *5*--emulsion breakdown unit; *6*--settling tank; *7*--commercial reservoir; *8*--UPR; I--hydrated oil from the Zapadno-Surgutskoye, Solkinskoye, and Bystrinskoye oilfields; II--reflux water introduced before the final separation unit; III--reagent working solution; IV--pure reagent; V--oil after settling; VI--gas; VII--industrial water; VIII-reflux water in the emulsion breakdown unit; IX--drain water at treatment plants; X--oil from commercial reservoir

Table 1

Equipment, Apparatus, Fittings	"Surgutneft'" NGDU's TKhU-2,3	"Yuganskneft'" NGDU's UPN-8
Centrifugal mixing pump	3K-6	4MS-10-2×4
Delivery volume, m^3/hr	45	60
Dosing piston pump	ND-100/10	ND-40/25
Delivery volume, liters/hr	100	40
Receiving tank, m^3	0.5	1.5
Flow meters on reagent pipelines		
Primary	DMPK-100	DMPK-100
Secondary	PV 10-1E	PV 10-1E
Measurement limits, m^3	4-10	4-10

reagent and oil is adjusted such that the reagent concentration in the working solution would be not greater than 0.5 percent.

The working solution is fed by the same pump to the first and second dehydration stages in a particular ratio.

To prevent possible settling of undissolved reagents out of solution, the working solution must be subjected to turbulent movement at a rate $v = 1\text{-}2$ m/sec, which is achieved by selecting a pipeline of the appropriate diameter.

Table 2

Indicators	Parameter Magnitude	
	UPN-8	TKhU-2
Unit's productivity in relation to commercial oil, tons/hr	1300-1700	600-700
Water concentration of well product, %	60-70	30-40
Temperature, °C, of:		
Hydrated oil	35-38	18-20
Initial dehydration	38-40	27-30
Final dehydration	48-50	48-54
Drain water consumption by emulsion breakdown unit, m^3/hr	160-310	100-170
Pressure at final separation stage, kg/cm^2	0.5	0.5
Pressure in settling tanks, kg/cm^2	3.5-4	3-4

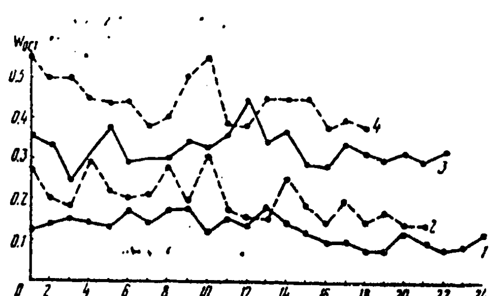

Figure 2. Extent of Oil Dehydration, W_{OCT}, by the "Yuganskneft'" NGDU's UPN-8 Unit (*1*,*2*) and the "Surgutneft'" NGDU's TKhU-2 Unit (*3*,*4*): reagents are dosed in the form of oil solutions, and in undiluted form: *1*--first type of reagent, oil solution, consumption 15-20 gm/tons; *2*--first type of reagent, undiluted reagent, consumption 30-35 gm/ton; *3*--second type of reagent, oil solution, consumption 27-31 gm/ton; *4*--second type of reagent, undiluted reagent, consumption 45-55 gm/ton; *1*,*4*--daily averages; *2*,*3*--shift averages (12 hours)

Research results established that working oil solutions of oil-soluble demulsifiers are easily prepared at a concentration of 0.2-0.5 percent with such a unit. In view of the limited solubility of demulsifiers in oil, a certain fraction of them remains in pure form in the system, while another fraction exists as a finely dispersed and rather stable emulsion.

The unit can also be used to prepare water solutions of water-soluble demulsifiers.

Oil solutions of oil-soluble demulsifiers were subjected to industrial tests in preparation of oil by the "Yuganskneft'" NGDU's UPN-8 system and the "Surgutneft'" NGDU's TKhU-2 system in order to evaluate the effectiveness of their action. For comparison purposes, the reagents were also tested when dosed in undiluted form. The basic parameters of the oil preparation process for the testing period are shown in Table 2.

The oil subjected to preparation is highly emulsified, and it is characterized by relatively high density (0.87-0.89 gm/cm^3) and viscosity (30-40 centistokes at 20°C), and a high concentration of tar (9-10 percent) and asphaltenes (3-4 percent).

Figure 2 shows the results of tests run with the demulsifiers. For the UPN-8, unit consumption of the first type of reagent, dosed in the form of an oil solution, is twice lower than when the solution is dosed in undiluted form (15-20 gm/ton as opposed to 30-35 gm/ton respectively), while for the TKhU-2, consumption of the second type of reagent is an average of 1.7 times lower (27-31 as opposed to 45-55 gm/ton), given simultaneous preparation of higher-quality oil.

This procedure for dosing oil-soluble demulsifiers in the form of oil solutions has been recommended for extensive introduction at West Siberian oilfields.

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OIL PREPARATION AT SOUTHERN OILFIELDS OF PERMSKAYA OBLAST

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 pp 39-40

[Article by M. G. Isayev and L. M. Shipiguzov]

[Text] Oil in the fields of southern Permskaya Oblast is heavy, highly viscous, and it has a high concentration of resins and asphaltenes. Moreover the structural complexity of these oilfields is compounded by a number of isolated uplifts and structures. As a result the oil collecting systems are drenched, and it takes 2-20 hours and more for emulsion to reach the central collection points.

The stability of water-oil emulsions depends on the presence and state of natural stabilizers in the oil. "Aging" of the emulsion proceeds with time, and it is practically completed after 20-24 hours. In this case emulsion "aging" proceeds slowly as asphaltic-resinous components dominate in the stabilizer composition, and the reverse is true when the isopropanol fraction--that is, the "paraffin" component--dominates.

The "paraffin" component dominates in oil stabilizers of Permskaya Oblast, having a concentration from 45 percent (Osinskoye oilfield) to 79.5 percent (Kamennolozhskoye oilfield); consequently emulsion in Permskaya Oblast exhibits a tendency for fast "aging"--that is, stably formed emulsion reaches the central collecting points. High temperatures (up to 60-80°C) and high demulsifier consumption (up to 150-200 gm/ton) are required for breakdown of this emulsion by the thermochemical method. Under these conditions a combined process of oil collection and preparation plays a great role in preventing "aging" of the emulsion; also important are early introduction of the reagent and utilization of the gas-hydrodynamic effect.

It was established in laboratory research that when the time of contact between the demulsifier and emulsion is increased, a positive impact is achieved; in winter, however, this impact is not enough to insure preparatory removal of water. The temperature of the process plays a significant role in this case (Figure 1).

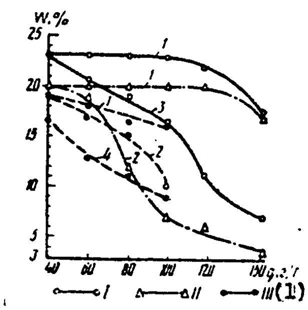

Figure 1. Concentration of Residual Water in Oil From the Osinskoye (I), Mayachnoye (II), and Nozhovskoye Oilfields (III) After One Hour Settling Time, Depending on Surfactant Dose, at Temperatures of 5 (*1*), 10 (*2*), 17 (*3*), and 20°C (*4*)

Key:
1. gm/ton

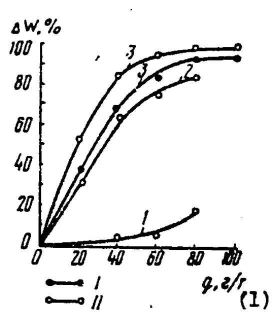

Figure 2. Dependence of the Dynamics of Water Removal From 30 Percent (*I*) and 60 Percent Emulsion (*II*) on Initial Water Concentration at Temperatures of 5 (*1*), 10 (*2*), and 20°C (*3*)

Key:
1. gm/ton

Thus for oil from the Osinskoye and Mayachnoye oilfields, a reagent dose of up to 150 gm/ton must be used to separate emulsion at 5°C; this dose does not produce a result with Pavlovskoye oil, and even a dose of up to 300 gm/ton is not enough for Gozhanskoye oil. Oil from the Nozhovskoye oilfield separates at as low a dose as 60 gm/ton, but the quantity of water that separates out is insignificant.

Raising the temperature has a positive influence. At a temperature of 10°C, emulsion from the Mayachnoye oilfield begins to separate at a surfactant dose of 60 gm/ton; in order to achieve separation of Osinskoye oil at this dose, the temperature must be raised to 17°C. Raising the temperature to 20°C reduces the dose required for Nozhovskoye oil to 40 gm/ton.

The initial water concentration also has a great influence (Figure 2). When a reagent dose of 20 gm/ton is added, emulsion from the Gondyrevskoye oilfield separates; when the water concentration is 30 percent, a third of the emulsified water separates out of the emulsion, while at 60 percent more than half of the water separates out. As the surfactant dose increases, this difference first rises and then declines, while the concentration of residual water in settled oil levels out.

Prolonged contact between the reagent and the emulsion reduces the amount of reagent needed; however, to acquire quality standardized oil at temperatures up to 20°C--that is, by means of in-pipeline demulsification, the settling time must be 6-10 hours, since the oil is highly viscous and the difference between the density of water and the oil is insignificant.

At the same time up to 80-90 percent of the water settles in the first 15-30 minutes (Figure 3). Consequently the settling time is governed by the remaining finely dispersed fraction of emulsified water, which is of significantly lower volume.

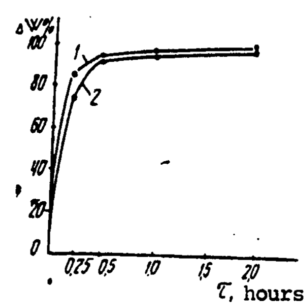

Figure 3. Dynamics of Water Settling Following Early Reagent Introduction ($t = 20°C$) for Oil From the Osinskoye (*1*) and Kuyedinskoye Oilfields (*2*)

When the emulsion is allowed to settle at high temperatures (40-60°C) and reagent is introduced early, settling time could be decreased to 1.5-2 hours while decreasing reagent consumption by 30-40 percent. Thus when thermochemical dehydration is involved, oil of the Kuyedinskoye group requires a surfactant dose of 120 and 150 gm/ton (at 60 and 40°C respectively). By introducing the reagent into the collection system and dumping the water beforehand, we can reduce the reagent dose to 70-90 gm/ton (at the same temperatures). Field tests conducted at the Kuyedinskaya TKhU [not further identified] in 1976-1978 confirmed the laboratory results indicating that the most sensible method for preparing heavy oil in Permskaya Oblast is an integrated method combining early reagent introduction, preliminary water dumping, and subsequent settling at high temperatures.

In the first tests, the reagent was introduced at the intake of the crude pump. Samples taken from reservoirs of different deposits and their mixtures showed that stably formed emulsion having an aggregate stability equal to 93 percent was reaching the TKhU. Separation of water was not observed in the crude reservoir. When reagent was introduced and the emulsion was passed through the pump, the aggregate stability dropped by a factor of 20. With this method, quality certified oil (with a water concentration less than 1 percent) was obtained at reagent doses of 120 gm/ton and higher, which corresponds to the dose determined in the laboratory. However, in all cases the oil leaving the settling tanks contained aggregate-stable water--that is, water in indestructible protective globules. Recirculation of hot drain water did not produce any results in this case.

After the point at which reagent was introduced was moved to the distribution manifold, the degree of emulsion breakdown increased dramatically, but the reagent dosage remained at the 100 gm/ton level. Once again water was observed to pass out of the settling tanks in protective globules. Water separation proceeded weakly in the initial discharging reservoir, and recirculation of hot drain water improved the results insignificantly.

Early reagent introduction was initiated in 1978 in the Kuyedinskoye group of oilfields. Dosing was performed at the Gozhano-Shagirtskoye (DNS-1) and Gondyrevskoye (DNS-4) oilfields, such that the two main wings of the collection system were affected. Oil from the Kuyedinskaya area remained untreated; it passes to the TsPPS [not further identified] directly from the GZU [not further identified], and it collects together only at the switching unit.

An analysis was performed on samples taken from the collection system and the TKhU (see table).

As we can see from the table, introduction of the reagent at DNS-1 is insufficient; the two BR-2.5 blocks could not provide a large enough dose to break down the emulsion (55-60 gm/ton). When oil was added at the Byrkinskoye and Al'nyashskoye deposits, the dose dropped to 45 gm/ton, while the aggregate stability was 20 percent--that is, complete emulsion breakdown was not achieved. Addition of oil in the Krasnoyarskaya area decreased the dose and the degree of emulsion breakdown even more. Thus emulsion that was less than one-third broken down entered the distribution manifold. A reagent dose of 47 gm/ton at the Gondyrevskoye oilfield almost completely broke down the emulsion, which is also close to the result of the laboratory studies (35 gm/ton).

Sampling Point (in Collection System and TKhU)	Reagent Consumption gm/ton	Reagent-Emulsion Contact Time, Hr	Emulsion Water Concen-tration,%	Aggregate Stability, %
DNS-1 at reagent introduction point*	55	--	23	74
From the Gozhan TsPPS reservoir to junction of DNS-3**	45	14.8	36.5	20
From Gozhan-TsPPS reservoir to TsPPS manifold	23.5	16.5	40.2	73
From Gondyr'-TsPPS reservoir to TsPPS manifold	47	6.3	40	7
From Kuyedinskaya area reservoir to TsPPS manifold	Net	--	21	98
Crude from manifold, after mixing of flows	21	--	35	58
Crude after introduction of reagent (without and together with reflux water)	117	0.2	55	1.4

* Gozhano-Shagirtskoye oilfield.
** Krasnayarskaya area.

Mixing of the reagent-treated flows with untreated oil from the Kuyedinskaya area produced an emulsion having an aggregate stability of 58 percent--that is, almost half of the emulsion was broken down with a total reagent dose of only 21 gm/ton. Additional reagent resulted in almost complete breakdown of emulsion, both without circulating hot drain water, and with circulating water. Consequently extensive emulsion breakdown was achieved by partial introduction of reagent into the collection system and additional introduction at the manifold. While introduction of reagent only at the manifold resulted in a three-time decrease in the aggregate stability in 10-12 minutes of contact, additional introduction of reagent into pretreated emulsion reduced the aggregate stability by 40 times. However, significant stratification of the emulsion was not observed at 13°C (without circulation of hot water). Returning water raised the temperature of the flow by 5° and resulted in intensive separation of water. Further passage of the emulsion through the TKhU system was accompanied by its breakdown in approximately the same proportions as seen with introduction of reagent at the TKhU, except that oil not containing aggregate-bound water and satisfying the appropriate commercial quality requirements left the settling tanks.

Thus use of an integrated method significantly raised oil quality, and further research on the production process revealed a way to reduce reagent consumption to 85 gm/t and limit its introduction to just the collection system alone. In this case almost 70 percent of the emulsified water is separated at the initial dumping stage.

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CONDITIONS FOR DEHYDRATION OF HIGHLY VISCOUS OIL USING HYDROCARBON DILUENTS

Moscow NEFTEPROMYSLOVOYE DELO in Russian No 4, 1980 pp 42-43

[Article by M. Yu. Tarasov]

[Text] The highly viscous, heavy oil from the Russkoye oilfield forms stable water-oil emulsion which can be extensively dehydrated at high demulsification temperatures with the use of a significant dose of demulsifier. One of the ways for improving demulsification of Russkoye oil is to mix it with light hydrocarbon diluents that reduce the viscosity and density of the well product.

A rational experiment planning method* was used to reduce the duration of experiments involving the broad range of parameters influencing dehydration (concentration of the diluent in the mixture, temperature, the water concentration in the oil, the dose of the dimulsifier, and so on). An experimental schedule was compiled foreseeing 25 experiments involving different combinations of quantitative values of six independently varying parameters: oil water concentration ($W = 10$, 20, 30, 40, 50 percent); emulsion dehydration temperature ($t = 20$, 35, 50, 65, 80°C); concentration of hydrocarbon diluent in oil phase ($C = 0$, 5, 10, 15, 20 percent); demulsifier dose ($C_p = 20$, 40, 60, 80, 100 gm/ton of oil); emulsion mixing intensity during preparation ($n = 500$, 1,000, 1,500, 2,000, 2,500 min^{-1}); time of contact between emulsion and demulsifier ($\tau =$ 10, 20, 30, 40, 50 min).

Oil sampled from the mouth of well 44 of the Russkoye oilfield was analyzed. The water concentration of the initial oil was 1.9 percent. Water-oil emulsions were prepared for 10 minutes in a $0.15 \cdot 10^{-3}$ m^3 propeller mixer at 20°C. The aqueous phase consisted of 2 percent sodium chloride solution in distilled water. The emulsion was kept at dehydration temperature thermostatically in the mixture for 30 minutes. Mixing intensity was

* Protod'yakonov, M. M., and Teder, R. I., "Metodika ratsional'nogo planirovaniya eksperimentov" [The Method of Rational Experiment Planning], Moscow, Izd-vo Nauka, 1970, p 75.

500 min^{-1}. Then hydrocarbon diluent (brand 70-100 petroleum ether) was added to the emulsion, and the demulsifier (Separol 5084) was dosed with a microsyringe in concentrated form. The diluted emulsion was processed by the demulsifier for a particular amount of time, after which it was drained into a glass calibrated settling tank. After being allowed to settle for 60 min, samples were taken from the upper part of the settling tank; these samples were used to determine the residual water concentration, $W_{ОСТ}$, by the Dean-Stark method.

Treatment of the experimental data produced the dependence of the concentration of residual water in the oil on factors of influence; the data were successively grouped on the basis of the parameter with the strongest action, after which the raw data were averaged and corrected to the mean value of the parameter with the strongest action. The following dependence was obtained:

$$W_{\text{ост}} = \frac{1}{0{,}033 + 2{,}34 \cdot 10^{-3} t} + 2{,}5 \cdot 10^{-3} \times$$
$$\times (C_p - 30)^2 + 8{,}94 \exp(-2{,}9 \cdot 10^{-3} |n - 1500|) -$$
$$-0{,}59\, C + 14{,}9 \exp(-0{,}144 |\tau - 42|) - 4{,}85.$$

Dependence of the residual concentration of water by weight, $W_{ОСТ}$, in emulsion from the Russkoye oilfield (water concentration--30 percent, temperature--50°C, demulsifier dose--40 gm/t) on concentration of hydrocarbon diluent by volume, C.

The formula can be used to quantitatively evaluate the domain within which dehydration of the analyzed oil is the most extensive. This domain is bounded by a temperature range of 40-60°C, demulsifier doses of 20-40 gm/ton oil, and 15-20 percent concentrations of diluent in the oil phase. We can see from the formula that the initial water concentration within the emulsion does not have a significant influence on the residual concentration of water in oil. The most stable emulsions, for which the mean water globule diameter is 1.5-3 μ, are obtained at a mixing intensity of 1,500 min^{-1}. As the mixing intensity is increased (above 1,500 min^{-1}), globule

C, %	$W_{ост}$, %, при $C_р$, г/т нефти(1)						
	10	20	30	40	60	70	80
15	0,57	0,34	0,53	0,26	(2) Следы	0,31	0,19
20	0,12	0,39	0	0	—	—	—

Note: At $C_p = 50$ gm/m, $W_{OCT} = 0$.

Key:

1. W_{OCT}, %, at C_p, gm/ton oil
2. Trace

diameter grows, which is probably associated with crowding of the globules against the wall of the mixer. Consequently it would be difficult to achieve extensive dehydration of the analyzed oil without adding hydrocarbon diluent.

A number of additional experiments were conducted, using the method described above, in order to clarify the quantitative values for the demulsifier doses and the concentrations of the hydrocarbon diluent at which dehydration is most effective. The dehydration temperature was 50°C, mixing intensity during emulsion preparation was 2,500 min^{-1}, the time of contact between emulsion and demulsifier was 20 min, and the concentration of water in the emulsion was 30 percent.

The results of the experiments are shown in the figure and table.

The analysis results demonstrate the possibility for extensive dehydration of the analyzed oil when the concentration of hydrocarbon diluent in the oil phase is 20 percent and higher. In this case the optimum demulsifier dose is 30-50 gm/ton, and the optimum dehydration temperature is 40-60°C.

Thus the rational planning method makes it possible to significantly reduce the number of experiments in the effort to find the domain within which the most effective dehydration of oil occurs.

Use of light hydrocarbon diluents significantly improves demulsification of oil from the Russkoye oilfield.
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